Appendix A to the
Proxy Statement

American Electric Power

2016 Annual Report

Audited Consolidated Financial Statements and
Management's Discussion and Analysis of Financial Condition and Results of Operations

BOUNDLESS ENERGY

AMERICAN ELECTRIC POWER
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CONTENTS

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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 East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP Renewables	AEP Renewables, LLC, a wholly-owned subsidiary of Energy Supply and a consolidated variable interest entity formed for the purpose of providing utility scale wind and solar projects whose power output is sold via long-term power purchase agreements to other utilities, cities and corporations.
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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in the deregulated Ohio and Texas market.
AEPRO	AEP River Operations, LLC.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP Utilities	AEP Utilities, Inc., a former subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. Effective December 31, 2016, TCC and TNC were merged into AEP Utilities, Inc. Subsequently following this merger, the assets and liabilities of CSW Energy, Inc. were transferred to an affiliated company and AEP Utilities, Inc. was renamed AEP Texas Inc.
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.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CWIP	Construction Work in Progress.

Term	Meaning
DCC Fuel	DCC Fuel VI LLC, DCC Fuel VII, DCC Fuel VIII, DCC Fuel IX and DCC X, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
Desert Sky	Desert Sky Wind Farm, a 160.5 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy 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.
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.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
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.

Term	Meaning
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.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PIRR	Phase-In Recovery Rider.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
Price River	Rights and interests in certain coal reserves located in Carbon County, Utah.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Putnam	Rights and interests in certain coal reserves located in Putnam, Mason and Jackson Counties, West Virginia.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, APCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 534 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	Formerly AEP Texas Central Company; now a division of AEP Texas.

Term	Meaning
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.
TRA	Tennessee Regulatory Authority.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Transource Missouri	A 100% wholly-owned subsidiary of Transource Energy.
Trent	Trent Wind Farm, a 150 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements 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 and the performance of generation plants.
- The ability to recover fuel and other energy costs through regulated or competitive electric rates.
- The ability to build transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- The ability to constrain operation and maintenance costs.
- The ability to develop and execute a strategy based on a view regarding prices of electricity and gas.
- Prices and demand for power generated and sold at wholesale.
- Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.
- The ability to recover through rates 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 this report.

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

AEP COMMON STOCK AND DIVIDEND INFORMATION

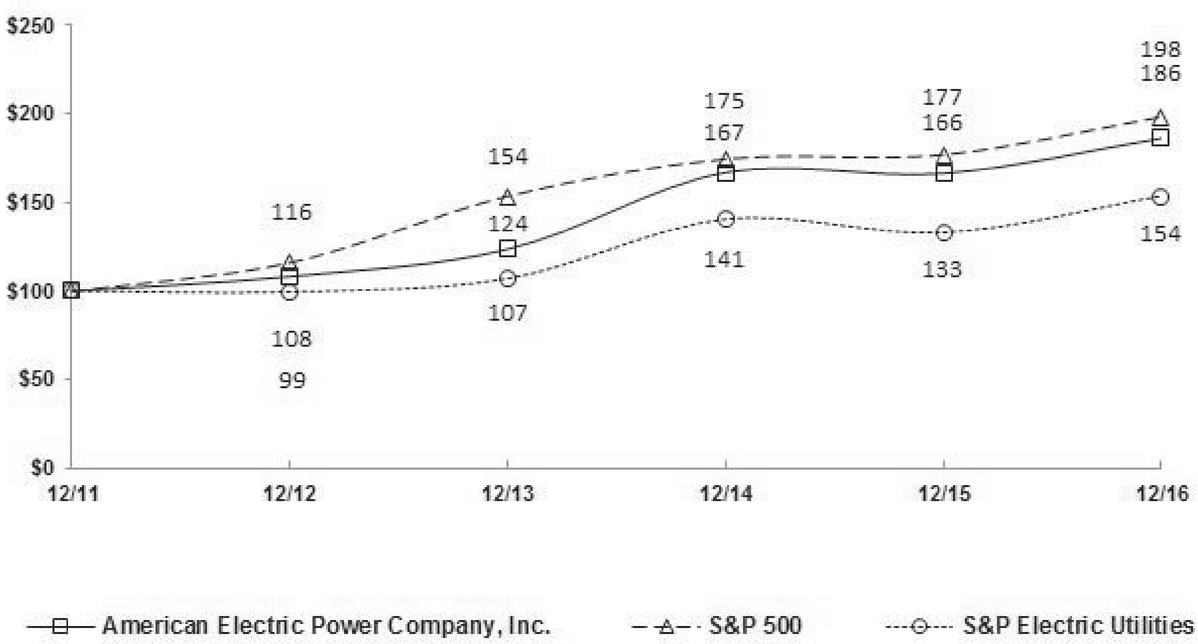
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended		High		Low		Quarter-End Closing Price		Dividend
December 31, 2016	$	65.25	$	57.89	$	62.96	$	0.59
September 30, 2016		71.32		63.56		64.21		0.56
June 30, 2016		70.10		61.42		70.09		0.56
March 31, 2016		66.49		56.75		66.40		0.56
December 31, 2015	$	59.52	$	53.30	$	58.27	$	0.56
September 30, 2015		59.18		52.29		56.86		0.53
June 30, 2015		58.35		52.32		52.97		0.53
March 31, 2015		65.38		54.66		56.25		0.53

AEP common stock is traded principally on the New York Stock Exchange. As of December 31, 2016, AEP had approximately 66,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., the S&P 500 Index, and the S&P Electric Utilities Index



*$100 invested on 12/31/11 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2016 (a)	2015	2014	2013	2012
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$16,380.1	$16,453.2	$16,378.6	$14,813.5	$14,298.4
Operating Income	$ 1,207.1	$ 3,333.5	$ 3,127.4	$ 2,822.5	$ 2,620.7
Income from Continuing Operations	$ 620.5	$ 1,768.6	$ 1,590.5	$ 1,473.9	$ 1,247.7
Income (Loss) From Discontinued Operations, Net of Tax	(2.5)	283.7	47.5	10.3	14.5
Net Income	618.0	2,052.3	1,638.0	1,484.2	1,262.2
Net Income Attributable to Noncontrolling Interests	7.1	5.2	4.2	3.7	3.4
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 610.9	$ 2,047.1	$ 1,633.8	$ 1,480.5	$ 1,258.8
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$62,036.6	$65,481.4	$63,605.9	$59,646.7	$56,817.4
Accumulated Depreciation and Amortization	16,397.3	19,348.2	19,970.8	19,098.6	18,529.6
Total Property, Plant and Equipment – Net	$45,639.3	$46,133.2	$43,635.1	$40,548.1	$38,287.8
Total Assets	$63,467.7	$61,683.1	$59,544.6	$56,321.0	$54,272.1
Total AEP Common Shareholders' Equity	$17,397.0	$17,891.7	$16,820.2	$16,085.0	$15,237.2
Noncontrolling Interests	$ 23.1	$ 13.2	$ 4.3	$ 0.8	$ 0.4
Long-term Debt (b)	$20,256.4	$19,572.7	$18,512.4	$18,198.2	$17,574.4
Obligations Under Capital Leases (b)	$ 305.5	$ 343.5	$ 362.8	$ 403.3	$ 306.3
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
From Continuing Operations	$ 1.25	$ 3.59	$ 3.24	$ 3.02	$ 2.57
From Discontinued Operations	(0.01)	0.58	0.10	0.02	0.03
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 1.24	$ 4.17	$ 3.34	$ 3.04	$ 2.60
Weighted Average Number of Basic Shares Outstanding (in millions)	491.5	490.3	488.6	486.6	484.7
Market Price Range:					
High	$ 71.32	$ 65.38	$ 63.22	$ 51.60	$ 45.41
Low	$ 56.75	$ 52.29	$ 45.80	$ 41.83	$ 36.97
Year-end Market Price	$ 62.96	$ 58.27	$ 60.72	$ 46.74	$ 42.68
Cash Dividends Declared per AEP Common Share	$ 2.27	$ 2.15	$ 2.03	$ 1.95	$ 1.88
Dividend Payout Ratio	183.06%	51.56%	60.78%	64.14%	72.31%
Book Value per AEP Common Share	$ 35.38	$ 36.44	$ 34.37	$ 32.98	$ 31.35

(a) The 2016 financial results include pretax asset impairments of $2.3 billion (see Note 7 to the financial statements).
(b) Includes portion due within one year.

EXECUTIVE OVERVIEW

Company Overview

AEP is one of the largest investor-owned electric public utility holding companies in the United States. AEP's electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

AEP's subsidiaries operate an extensive portfolio of assets including:

- Approximately 224,000 miles of distribution lines that deliver electricity to 5.4 million customers.
- Approximately 40,000 miles of transmission lines, including 2,114 miles of 765 kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- AEP Transmission Holdco has approximately $4.4 billion of transmission assets in-service.
- Approximately 31,000 megawatts of generating capacity in 3 RTOs as of December 31, 2016, one of the largest complements of generation in the United States. After the sale of certain generation assets in January 2017, AEP has approximately 26,000 megawatts of generating capacity.

Customer Demand

AEP's weather-normalized retail sales volumes for the year ended December 31, 2016 decreased by 0.2% from the year ended December 31, 2015. AEP's 2016 industrial sales volumes decreased 1.4% compared to 2015 primarily due to decreased sales to customers in the manufacturing sector. Weather-normalized residential sales volumes were flat and commercial sales increased by 0.9% in 2016, respectively, from 2015.

In 2017, AEP anticipates weather-normalized retail sales volumes will increase by 0.7%. The industrial class is expected to increase by 1.5% in 2017, primarily related to a number of new oil and natural gas expansions, especially around the major shale gas areas within AEP's footprint. Weather-normalized residential sales volumes are projected to increase by 0.2%, primarily related to projected customer growth. Weather-normalized commercial sales volumes are projected to increase by 0.3%.

Ohio Global Settlement

In February 2017, the PUCO approved a settlement agreement (Global Settlement) filed by OPCo in December 2016. The parties to the Global Settlement include OPCo, the PUCO staff and various intervenors. The Global Settlement resolves all remaining open issues on remand from the Ohio Supreme Court in OPCo's 2009 - 2011 and June 2012 - May 2015 ESP filings, including issues related to carrying charges on the PIRR and issues related to the RSR capacity charges. It also resolves all open issues in OPCo's 2009, 2014 and 2015 SEET filings and 2009, 2012 and 2013 Fuel Adjustment Clause Audits.

The significant components of the Global Settlement include:

Remands Related to the PIRR

All applicable parties participating in this settlement will withdraw their pending applications for rehearing of the PUCO order that allowed for the reinstatement of the equity portion of the weighted average cost of capital (WACC) rate on previously deferred fuel balances. As part of the Global Settlement, the PIRR rate to be collected from customers through December 2018 will be reduced by $97 million.

Remands Related to the RSR

Beginning January 2017, OPCo will be entitled to collect $388 million in RSR revenues over a total of 30 months, subject to true up at the end of the collection period in June 2019. Current RSR rates will continue until the new RSR rates are approved. The Global Settlement resolves the issues related to the non-deferral portion of RSR collections and the impact of the appropriate energy credit on capacity charges. In December 2016, OPCo recorded an increase in Regulatory Assets on the balance sheets for the deferral of $83 million in RSR capacity costs and $14 million in related debt carrying charges with a corresponding decrease in expense in Generation Deferrals and an increase in Carrying Costs Income, respectively, on the statements of income.

For the year ended December 31, 2016, AEP recorded approximately $97 million in RSR capacity deferrals and related carrying charges to the following line items on the statements of income:

	AEP (in millions)	
Fuel and Other Consumables Used for Electric Generation	$	(19.0)
Purchased Electricity for Resale		(19.9)
Other Operation		(15.7)
Depreciation and Amortization		(42.1)
Total Decrease in RSR Expenses	$	(96.7)

As of December 31, 2016, OPCo's total RSR under-recovery balance, including carrying charges, was $299 million.

Remands Related to the SEET

As part of the Global Settlement, $20 million will be returned to customers over a 12-month period commencing within 45 days of the final PUCO order adopting the Global Settlement. The Global Settlement states that this obligation has no precedential effect on OPCo's SEET methodology. In addition, the parties agreed that earnings were not significantly excessive in 2015. In December 2016, OPCo accrued $20 million in Other Current Liabilities on the balance sheets with a corresponding decrease in Electricity, Transmission and Distribution revenues (Transmission and Distribution Utilities for AEP) on the statements of income. The Global Settlement resolves the issues related to the 2014 and 2015 SEET proceedings.

Fuel Adjustment Clause Proceedings

OPCo will refund $100 million paid by SSO customers from August 2012 - May 2015 related to OVEC and Lawrenceburg purchases. In December 2016, OPCo accrued $100 million in Other Current Liabilities on the balance sheets with a corresponding decrease in Electricity, Transmission and Distribution revenues (Transmission and Distribution Utilities for AEP) on the statements of income. The Global Settlement resolves the claimed recovery of fixed fuel costs through both the FAC and the approved capacity charges. This refund will be a one-time credit that will be applied the earlier of either 45 days after the final non-appealable order from the PUCO adopting the Global Settlement, or the December 2017 billing cycle.

Also see "OPCo Rate Matters" section of Note 4.

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 the 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 Distribution Technology Rider and a Renewable Resource Rider.

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

Merchant 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. As of December 31, 2016, the net book value of these assets, including related materials and supplies inventory and CWIP, was $1.8 billion. The sale closed in January 2017 for approximately $2.2 billion. The net proceeds from the transaction are 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 $130 million. AEP plans to primarily use 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 7 for additional information.

In September 2016, due to AEP’s ongoing evaluation of strategic alternatives for its merchant generation assets, declining forecasts of future energy and capacity prices, and a decreasing likelihood of cost recovery through regulatory proceedings or legislation in the state of Ohio providing for the recovery of AEP’s existing Ohio merchant generation assets, AEP performed an impairment analysis at the unit level on the remaining merchant generation assets in accordance with accounting guidance for impairments of long-lived assets. The evaluation was performed using generating unit specific estimated future cash flows and resulted in a material impairment of certain merchant generation fleet assets. As a result, AEP recorded a pretax impairment of $2.3 billion ($1.5 billion, net of tax) in Asset Impairments and Other Related Charges on the statements of income related to 2,684 MWs of Ohio merchant generation including Cardinal, Unit 1, 43.5% ownership interest in Conesville, Unit 4, Conesville, Units 5 and 6, 26.0% ownership interest in Stuart, Units 1-4, and 25.4% ownership interest in Zimmer, Unit 1, as well as Putnam coal and I&M’s Price River coal reserves, Desert Sky and Trent Wind Farms and the merchant generation portion of the Oklaunion Plant. As of December 31, 2016, the remaining net book value of these assets is $57 million. See “Merchant Generating Assets (Generation & Marketing Segment)” section of Note 7 for additional information.

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. In February 2017, AEP signed an agreement to purchase Dynegy Corporation’s 40% ownership share of Conesville Plant, Unit 4. Simultaneously, AEP signed an agreement to sell its 25.4% ownership share of Zimmer Plant, Unit 1 to Dynegy Corporation. The transactions are expected to close in the second quarter of 2017, subject to FERC approval and are not expected to have a material impact on net income, cash flows and financial condition. AEP is also continuing a separate strategic review and evaluating alternatives related to the 48 MW Racine Hydroelectric Plant. 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.

AEP has formed two new 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 of cost reducing energy technologies. AEP OnSite Partners, LLC pursues projects where a suitable termed agreement is entered into with a credit-worthy counterparty. AEP Renewables, LLC develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with credit-worthy counterparties. These subsidiaries have approximately 41 MWs of renewable generation projects in operation and 83 MWs of renewable generation projects under construction with an estimated financial commitment of approximately $226 million. As of December 31, 2016, $171 million of costs have been incurred related to these projects.

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%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This share of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under cost-based rate recovery in Texas, Louisiana, and through SWEPCo's wholesale customers under FERC-based rates. As of December 31, 2016, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP.

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

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased SWEPCo's Louisiana total rates by approximately $2 million annually, effective March 2013. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund. The settlement also provided that the LPSC would review base rates in 2014 and 2015 and that SWEPCo would recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. A hearing at the LPSC related to the Turk Plant prudence review is scheduled for June 2017. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition. See the "2012 Louisiana Formula Rate Filing" section of Note 4.

2016 Texas Base Rate Case

In December 2016, SWEPCo filed a base rate request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. The annual increase includes approximately (a) $34 million related to additional environmental controls to comply with Federal EPA mandates, (b) $25 million for additional generation, transmission and distribution investments and increased operating costs, (c) $8 million related to transmission cost recovery within SWEPCo's regional transmission organization and (d) $2 million in additional vegetation management.

If any of these costs are not recoverable, 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 cost a total of approximately $850 million, excluding AFUDC. As of December 31, 2016, SWEPCo had incurred costs of $397 million, including AFUDC, and had remaining contractual construction obligations of $11 million related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. In March 2016, SWEPCo filed a request with the APSC to recover $69 million in environmental costs related to the Arkansas retail jurisdictional share of Welsh Plant, Units 1 and 3, which was approved by the APSC in August 2016. SWEPCo began recovering the Arkansas jurisdictional share of these costs in March 2016, subject to review in the next filed base rate proceeding. In September 2016, SWEPCo filed an additional request to increase the Arkansas retail jurisdictional share of the environmental investment by $10 million, for a total of $79 million. SWEPCo implemented the increase in September 2016. In December 2016, the LPSC approved deferral of certain expenses related to environmental controls installed at Welsh Plant, until these investments are put into base rates. The eligible Welsh Plant deferrals through December 31, 2016 are $8 million, excluding $5 million of unrecognized equity, subject to review by the LPSC, and include a WACC return on environmental investments and the related depreciation expense and taxes. SWEPCo will seek recovery of its project costs from customers at the state commissions and the FERC. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" and "Climate Change, CO_2 Regulation and Energy Policy" sections of "Environmental Issues" below.

As of December 31, 2016, the net book value of Welsh Plant, Units 1 and 3 was $633 million, before cost of removal, including materials and supplies inventory and CWIP. In April 2016, Welsh Plant, Unit 2 was retired. Upon retirement, $76 million was reclassified as Regulatory Assets on the balance sheets related to the net book value of Welsh Plant, Unit 2 and the related asset retirement obligation costs. In SWEPCo's 2016 Texas Base Rate Case, SWEPCo requested recovery of the Texas jurisdictional share (approximately 33%) of the net book value of Welsh Plant, Unit 2 through 2042, the remaining life of Welsh Plant, Unit 3. Management will seek recovery of the remaining Welsh Plant, Unit 2 retirement-related regulatory assets in future rate proceedings.

If any of these costs are not recoverable, including retirement-related costs for Welsh Plant, Unit 2, it could reduce future net income and cash flows and impact financial condition. See the "Welsh Plant - Environmental Impact" section of Note 4.

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million. In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4, which would be recovered through the FAC.

In November 2016 and December 2016, the OCC issued orders that approved a net annual revenue increase of $19 million based upon a 9.5% return on common equity. The orders also included (a) approval to defer incurred costs related to PSO's environmental compliance plan until those costs are included in base rates, (b) no determination related to the return of and return on the post-retirement remaining net book value of Northeastern Plant, Unit 4 since the April 2016 retirement was outside of the test year, (c) approval to include environmental consumable costs in the FAC (d) the continued depreciation of Northeastern Plant, Units 3 and 4 through 2040 (no accelerated depreciation) and (e) altered the system reliability rider by eliminating the expense portion of the rider and setting the capital portion of the rider at the December 2016 plant balance and approved recovery of deferred expenses and return on the capital balance incurred prior to the effective date of new tariffs in January 2017. Additionally, the orders stated that the cost recovery of new PPAs related to replacement power resulting from the retirement of Northeastern Plant, Unit 4 will be addressed in a future FAC proceeding. Effective December 2016, interim rates were terminated and the refund of over collections began and will be completed no later than October 2017. In accordance with the final order, updated rates and tariffs went into effect in January 2017.

If any of these costs, including a return on Northeastern Plant, Unit 4, are ultimately not recoverable, it could reduce future net income and cash flows and impact financial condition. See the "2015 Oklahoma Base Rate Case" section of Note 4.

Indiana Amended PJM Settlement Agreement

In November 2016, the IURC issued an order that approved an amended settlement agreement between I&M and certain intervenors. This agreement amends a previously approved 2014 settlement agreement that addresses the recovery of 43.5% of certain transmission expenses through the Indiana PJM rider through 2017.

The amended agreement allows I&M to recover 100% of the Indiana jurisdictional share of these transmission expenses not recovered through base rates through the Indiana PJM rider, subject to a $109 million cap for the period January 2017 through June 2018. Beginning July 2018, I&M will be allowed to recover 100% of the Indiana jurisdictional share of these transmission expenses through the Indiana PJM rider, without a cap, until the issue is addressed by the IURC in a future proceeding, subject to the condition that I&M files a base rate case on or before January 2018. The amended agreement also provides for deferral of incremental vegetation management expenses over the period January 2017 through June 2018. Any vegetation management expenses deferred would reduce the cap for the transmission expenses described above. As part of the amended settlement, I&M agreed that it will not file a base rate case before July 2017 and will not implement new base rates prior to July 2018.

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. 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 life and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport Unit Power Agreement to affiliates, including I&M, with I&M's share recoverable in its base rates. 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 lease. A hearing at the IURC is scheduled for March 2017.

TCC and TNC Merger

Effective December 31, 2016, TCC and TNC merged into AEP Utilities, Inc., as approved by the FERC and the PUCT in September 2016 and December 2016, respectively. Upon merger, AEP Utilities, Inc. changed its name to AEP Texas Inc., but maintained TCC's and TNC's respective customer rates. The PUCT ordered certain post-merger conditions which included a) the sharing of certain interest rate savings with customers and b) an annual credit to customers of approximately $630 thousand for savings resulting from an expected reduction in post-merger debt issuance costs, effective until the next base rate case.

FERC Transmission Complaint and Proposed Modifications to Transmission Rates

In October 2016, several parties filed a joint complaint with the FERC claiming that the base return on common equity used by various AEP affiliates 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. In November 2016, AEP affiliates filed an application with the FERC to modify the FERC formula transmission rate calculation, including adjustments for certain tax issues and a shift from historical to estimated expenses with a proposed effective date of January 1, 2017. The rates will be implemented based upon the date provided in the pending FERC order, subject to refund. Management believes its financial statements adequately address the impact of the complaint and the proposed modifications to AEP's transmission rates in PJM. 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.

Virginia Legislation Affecting Biennial Reviews

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

In February 2016, certain APCo industrial customers filed a petition with the Virginia SCC requesting the issuance of a declaratory order that finds the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, directs APCo to make biennial review filings beginning in 2016. In July 2016, the Virginia SCC issued an order that denied the petition. In July 2016, the industrial customers filed an appeal of the order with the Supreme Court of Virginia. Management is unable to predict the outcome of these challenges to the Virginia legislation. If the biennial review process is reinstated in advance of March 2020, it could reduce future net income and cash flows and impact financial condition.

PJM Capacity Market

AGR is required to offer all of its available generation capacity in the PJM Reliability Pricing Model (RPM) auction, which is conducted three years in advance of the delivery year.

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

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

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

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

In August 2015, PJM held its first base residual auction implementing CP rules for the June 2018 through May 2019 period. AGR cleared 7,209 MWs at the CP auction price of $164.77/MW-day. The base residual auction for the June 2019 through May 2020 period was conducted in May 2016. AGR cleared 7,301 MWs at the CP auction price of $100/MW-day. Shown below are the results for the June 2018 through May 2019 and June 2019 through May 2020 periods:

PJM Auction Period	Capacity Performance Auction Price	Base Capacity Auction Price
	(dollars per MW day)	(dollars per MW day)
June 2018 through May 2019	164.77	150.00
June 2019 through May 2020	100.00	80.00

After the sale of the Darby, Gavin, Lawrenceburg and Waterford Plants in January 2017, AGR is no longer responsible for and does not receive capacity revenue for the portion of the cleared capacity associated with these plants.

The FERC order exempted Fixed Resource Requirement (FRR) entities, including APCo, I&M, KPCo and WPCo, from the CP rules through the delivery period ending May 2019. Beginning in June 2019, FRR entities are subject to CP rules.

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 and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiff's claims. Several claims remained, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. The plaintiff subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiff's motion for partial judgment and filed a motion to dismiss the case for failure to state a claim. In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of all remaining claims with prejudice and the court subsequently entered a final judgment. In May 2016, Plaintiffs filed a notice of appeal 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. This matter is currently pending before the U.S. Court of Appeals for the Sixth Circuit. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

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

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

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 December 31, 2016, the AEP System had a total generating capacity of approximately 31,000 MWs, of which approximately 16,000 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the fossil generating facilities. Based upon management estimates, AEP's investment to meet these existing and proposed requirements ranges from approximately $4.3 billion to $4.9 billion through 2025.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans (SIPs) or federal implementation plans (FIPs) that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors. In addition, management is continuing to evaluate the economic feasibility of environmental investments on both regulated and competitive plants.

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

Company	Plant Name and Unit	Generating Capacity (in MWs)
AGR	Kammer Plant	630
AGR	Muskingum River Plant	1,440
AGR	Picway Plant	100
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant	600
I&M	Tanners Creek Plant	995
KPCo	Big Sandy Plant, Unit 2	800
Total		5,535

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

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

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

As of December 31, 2016, the net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the PSO and SWEPCo units listed above was $161 million. For Northeastern Station, 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. These regulatory assets are pending regulatory approval. 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. Management will seek recovery of the remaining PSO and SWEPCo regulatory assets in future rate proceedings.

In October 2015, KPCo obtained permits following the KPSC's approval to convert its 278 MW Big Sandy Plant, Unit 1 to natural gas. Big Sandy Plant, Unit 1 began operations as a natural gas unit in May 2016.

APCo obtained permits following the Virginia SCC's and WVPSC's approval to convert its 470 MW Clinch River Plant, Units 1 and 2 to natural gas. In the third and fourth quarters of 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Of the retired coal related assets for Clinch River Plant, Units 1 and 2, management plans to seek regulatory approval for $24 million. Clinch River Plant, Unit 1 and Unit 2 began operations as natural gas units in February 2016 and April 2016, respectively.

In January 2017, Dayton Power and Light Co. 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 Co. and are jointly owned by AGR and nonaffiliated entities. AGR owns 600 MWs of the Stuart Plant, Units 1-4. As of December 31, 2016, AGR's net book value before cost of removal, including related materials and supplies inventory and CWIP balances, of the Stuart Plant, Units 1-4 was $221 thousand.

To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Clean Air Act Requirements

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

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision was appealed to the U.S. Supreme Court, which reversed the decision and remanded the case to the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit ordered CSAPR to take effect on January 1, 2015 while the remand proceeding was still pending. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA. In September 2016, the Federal EPA finalized its response to the remand for ozone season NO_x budgets. In November 2016, the Federal EPA proposed to remove Texas from the annual SO_2 and NO_x budget programs. Texas would remain part of CSAPR's ozone season NO_x budget program. All of the states in which AEP's power plants are located are covered by CSAPR. See "Cross-State Air Pollution Rule" section below.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants in 2012, but the rule was remanded to the Federal EPA upon further review. The Federal EPA issued a supplemental finding, received comments and affirmed its decision on the MACT standards for power plants. That decision has been challenged in the courts but the rule remains in effect. See "Mercury and Other Hazardous Air Pollutants (HAPs) Regulation" section below.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) will address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. 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.

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 implementation of certain required controls. The final rule is being challenged in the courts. 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 settlement discussion but were unable to reach agreement. In January 2017, Federal EPA proposed source-specific BART requirements for SO_2 from sources in Texas, including certain AEP units. The comment period has not yet closed.

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.

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

The Federal EPA also issued new, more stringent national ambient air quality standards (NAAQS) for PM in 2012, SO_2 in 2010 and ozone in 2015. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for facilities as a result of those evaluations. Management cannot currently predict the nature, stringency or timing of those requirements.

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

Cross-State Air Pollution Rule

In 2011, the Federal EPA issued CSAPR as a replacement of CAIR. 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. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program, although the Federal EPA has proposed to withdraw the annual CSAPR budget programs in Texas. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. In 2012, the court issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "overcontrol" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. A petition for review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. In April 2014, the U.S. Supreme Court issued a decision reversing in part the decision of the U.S. Court of Appeals for the District of Columbia Circuit and remanding the case for further proceedings consistent with the opinion. The Federal EPA filed a motion to lift the stay and allow Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. The court granted the Federal EPA's motion. The parties filed briefs and presented oral arguments. In July 2015, the U.S. Court of Appeals for the District of Columbia Circuit found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The U.S. Court of Appeals for the District of Columbia Circuit remanded the rule to the Federal EPA to timely revise the rule consistent with the court's opinion while CSAPR remains in place.

In December 2015, the Federal EPA issued a proposal to revise the ozone season NO_x budgets in 23 states beginning in 2017 to address transport issues associated with the 2008 ozone standard and the budget errors identified in the U.S. Court of Appeals for the District of Columbia Circuit's July 2015 decision. The proposal was open for public comment through February 1, 2016. In October 2016, a final rule was issued that 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. Management believes that there are flaws in the underlying analysis of and justification for this rule. Management is evaluating compliance options for the 2017 ozone season, including any opportunity to further optimize NO_x emissions and availability of allowances.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of nonmercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance was required within three years. Management obtained a one-year administrative extension at several units to facilitate the installation of controls or to avoid a serious reliability problem.

In 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 Mercury and Air Toxics Standards (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. 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. The Federal EPA intends to finalize either a rate-based or mass-based trading program that can be enforced in states that fail to submit approved plans by the deadlines established in the final guidelines. The Federal EPA established a 90-day public comment period on the proposed rules and management submitted comments. In June 2016, the Federal EPA issued a separate proposal for the Clean Energy Incentive Program (CEIP) that was included in the model rules. Through the CEIP, states could issue allowances or credits for eligible actions prior to the first compliance period under the CPP. The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final Clean Power Plan, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review.

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

Coal Combustion Residual Rule

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

The final rule became effective in October 2015. The Federal EPA 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. The rule does not apply to inactive CCR landfills, surface impoundments at retired generating stations or the beneficial use of CCR. The rule is self-implementing so state action is not required. Because of this self-implementing feature, the rule contains extensive record keeping, notice and internet posting requirements. The CCR rule requirements contain a compliance schedule spanning an approximate four year implementation period. If CCR units do not meet these standards within the timeframes provided, they will be required to close. Extensions of time for closure are available provided there is no alternative disposal capacity or the owner can certify cessation of a boiler by a certain date. Challenges to the rule by industry associations of which AEP is a member are proceeding. In April 2016, the parties entered into a settlement agreement that would require the Federal EPA to reconsider certain aspects of the rule. In June 2016, the U.S. Court of Appeals for the District of Columbia issued an order granting the voluntary remand of certain provisions including the Federal EPA's issuance of a rule vacating the provision creating specific closure requirements for inactive surface impoundments that complete closure by April 17, 2018. In August 2016, the Federal EPA proposed a direct final rule to extend the deadlines for these facilities to comply with the CCR standards. The proposed rule received no adverse comments and became effective 60 days following publication. Management does not believe the direct final rule will have a significant impact on its planned pond closures. The Federal EPA will also use its best efforts to complete reconsideration of all of the affected provisions within three years.

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.

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

In February 2014, the Federal EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the Federal EPA supports these beneficial uses. Currently, approximately 40% of the coal ash and other residual products from AEP's generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Encapsulated beneficial uses are not materially impacted by the new rule but additional demonstrations may be required to continue land applications in significant amounts except in road construction projects.

Clean Water Act (CWA) Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The final rule affects all plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with the impingement standard and requires site-specific studies to determine appropriate entrainment compliance measures at facilities withdrawing more than 125 million gallons per day. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems, as defined in the rule, are not expected to require any technology changes. Facilities subject to both the impingement standard and site-specific entrainment studies will typically be given at least three years to conduct and submit the results of those studies to the permit agency. Compliance timeframes will then be established by the permit agency through each facility's National Pollutant Discharge Elimination System (NPDES) permit for installation of any required technology changes, as those permits are renewed over the next five to eight years. Petitions for review of the final rule were filed by industry and environmental groups and are currently pending in the U.S. Court of Appeals for the Second Circuit.

In addition, the Federal EPA developed revised effluent limitation guidelines for electricity generating facilities. A final rule was issued in November 2015. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In addition to other requirements, the final rule establishes limits on flue gas desulfurization wastewater, zero discharge for fly ash and bottom ash transport water and flue gas mercury control wastewater. The applicability of these requirements is as soon as possible after November 2018 and no later than December 2023. These new requirements will be implemented through each facility's wastewater discharge permit. Management continues to assess technology additions and retrofits.

In June 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The CWA provides for federal jurisdiction over "navigable waters" defined as "the waters of the United States." This jurisdictional definition applies to all CWA programs, potentially impacting generation, transmission and distribution permitting and compliance requirements. Among those programs are: permits for wastewater and storm water discharges, permits for impacts to wetlands and water bodies and oil spill prevention planning. The final definition continues to recognize traditional navigable waters of the U.S. as jurisdictional as well as certain exclusions. The rule also contains a number of new specific definitions and criteria for determining whether certain other waters are jurisdictional because of a "significant nexus." Management believes that clarity and efficiency in the permitting process is needed. Management remains concerned that the rule introduces new concepts and could subject more of AEP's operations to CWA jurisdiction, thereby increasing the time and complexity of permitting. The final rule is being challenged in both courts of appeal and district courts. Challengers include industry associations of which AEP is a member. The U.S. Court of Appeals for the Sixth Circuit granted a nationwide stay of the rule pending jurisdictional determinations. In February 2016, the U.S. Court of Appeals for the Sixth Circuit issued a decision holding that it has exclusive jurisdiction to decide the challenges to the "waters of the United States" rule. Industry, state and related associations 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.

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 AEP's wholly-owned transmission-only subsidiaries and transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

- 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. With the sale of AEPRO in November 2015, the activities related to the AEP River Operations segment have been moved to Corporate and Other for the periods presented. See "AEPRO (Corporate and Other)" section of Note 7 for additional information.

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. These expenses are generally collected from customers through cost recovery mechanisms. As such, management uses gross margin for internal reporting analysis as it excludes the fluctuations in revenue caused by changes 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 table below presents Earnings (Loss) Attributable to AEP Common Shareholders by segment for the years ended December 31, 2016, 2015 and 2014.

	Years Ended December 31,		
	2016	2015	2014
		(in millions)	
Vertically Integrated Utilities	$ 979.9	$ 896.5	$ 707.6
Transmission and Distribution Utilities	482.1	352.4	352.2
AEP Transmission Holdco	266.3	191.2	150.8
Generation & Marketing	(1,198.0)	366.0	367.4
Corporate and Other	80.6	241.0	55.8
Earnings Attributable to AEP Common Shareholders	$ 610.9	$ 2,047.1	$ 1,633.8

AEP CONSOLIDATED

2016 Compared to 2015

Earnings Attributable to AEP Common Shareholders decreased from $2 billion in 2015 to $611 million in 2016 primarily due to:

- An impairment of certain merchant generation assets.
- A decrease in generation revenues due to lower capacity revenue and a decrease in wholesale energy prices.

These decreases were partially offset by:

- A decrease in system income taxes primarily due to reduced pretax book income as a result of the impairment of certain merchant generation assets as well as the reversal of valuation allowances related to the pending sale of certain merchant generation assets and the settlement of a 2011 audit issue with the IRS, as well as favorable 2015 income tax return adjustments related to AEP's commercial barging operations.
- Favorable rate proceedings during 2016 in AEP's various jurisdictions.

2015 Compared to 2014

Earnings Attributable to AEP Common Shareholders increased from $1.6 billion in 2014 to $2 billion in 2015 primarily due to:

- Favorable rate proceedings during 2015 in AEP's various jurisdictions.
- The gain on the sale of commercial barge operations.
- An increase in transmission investment which resulted in higher revenues and income.
- A decrease in expenses due to a settlement and revision of certain asset retirement obligations.
- Favorable retail, trading and marketing activity.

These increases were partially offset by:

- A decrease in generation revenues due to lower capacity revenue.
- A decrease in off-system sales margins due to lower market prices and reduced sales volumes.
- An increase in depreciation and amortization expenses primarily due to higher depreciable base.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Years Ended December 31, 2016	2015	2014
		(in millions)	
Revenues	$ 9,091.9	$ 9,172.2	$ 9,484.4
Fuel and Purchased Electricity	3,079.3	3,413.6	3,953.4
Gross Margin	6,012.6	5,758.6	5,531.0
Other Operation and Maintenance	2,702.9	2,529.5	2,515.0
Asset Impairments and Other Related Charges	10.5	—	—
Depreciation and Amortization	1,073.8	1,062.6	1,033.0
Taxes Other Than Income Taxes	390.8	383.1	370.8
Operating Income	1,834.6	1,783.4	1,612.2
Interest and Investment Income	4.8	4.6	3.4
Carrying Costs Income	10.5	11.8	6.7
Allowance for Equity Funds Used During Construction	45.5	63.2	46.3
Interest Expense	(522.1)	(517.4)	(525.5)
Income Before Income Tax Expense and Equity Earnings	1,373.3	1,345.6	1,143.1
Income Tax Expense	397.3	449.3	433.5
Equity Earnings of Unconsolidated Subsidiaries	8.0	3.9	2.2
Net Income	984.0	900.2	711.8
Net Income Attributable to Noncontrolling Interests	4.1	3.7	4.2
Earnings Attributable to AEP Common Shareholders	$ 979.9	$ 896.5	$ 707.6

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31, 2016	2015	2014
		(in millions of KWhs)	
Retail:			
Residential	32,606	32,720	34,073
Commercial	25,229	25,006	25,048
Industrial	34,029	34,638	35,281
Miscellaneous	2,316	2,279	2,311
Total Retail	94,180	94,643	96,713
Wholesale (a)	23,081	25,353	34,241
Total KWhs	117,261	119,996	130,954

(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

	Years Ended December 31,		
	2016	**2015**	**2014**
		(in degree days)	
Eastern Region			
Actual – Heating (a)	2,541	2,710	3,313
Normal – Heating (b)	2,767	2,755	2,740
Actual – Cooling (c)	1,345	1,113	932
Normal – Cooling (b)	1,075	1,075	1,080
Western Region			
Actual – Heating (a)	1,130	1,379	1,840
Normal – Heating (b)	1,495	1,491	1,510
Actual – Cooling (c)	2,480	2,315	2,049
Normal – Cooling (b)	2,215	2,210	2,203

(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.

2016 Compared to 2015

Reconciliation of Year Ended December 31, 2015 to Year Ended December 31, 2016
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2015	$ 896.5
Changes in Gross Margin:	
Retail Margins	274.5
Off-system Sales	(18.7)
Transmission Revenues	(6.1)
Other Revenues	4.3
Total Change in Gross Margin	254.0
Changes in Expenses and Other:	
Other Operation and Maintenance	(173.4)
Asset Impairments and Other Related Charges	(10.5)
Depreciation and Amortization	(11.2)
Taxes Other Than Income Taxes	(7.7)
Interest and Investment Income	0.2
Carrying Costs Income	(1.3)
Allowance for Equity Funds Used During Construction	(17.7)
Interest Expense	(4.7)
Total Change in Expenses and Other	(226.3)
Income Tax Expense	52.0
Equity Earnings	4.1
Net Income Attributable to Noncontrolling Interests	(0.4)
Year Ended December 31, 2016	$ 979.9

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

- **Retail Margins** increased $275 million primarily due to the following:
  - The effect of rate proceedings in AEP's service territories which include:
    - A $158 million increase in rates in West Virginia and Virginia, which includes recognition of deferred billing in West Virginia as approved by the WVPSC in June 2016. This increase is partially offset by a 2015 adjustment affected by the amended Virginia law that has an impact on biennial reviews.
    - A $48 million increase for KPCo primarily due to increases in base rates and riders.
    - A $41 million increase for I&M due to increases in riders in the Indiana service territory.
    - A $26 million increase for PSO due to base rate increases implemented in January 2016 and rider revenues.
    - A $23 million increase for SWEPCo due to revenue increases from rate riders in Arkansas and Texas.

    For the increases described above, $177 million relate to riders/trackers which have corresponding increases in expense items below.
    - A $29 million increase in weather-related usage primarily in the eastern region.

  These increases were partially offset by:
    - A $22 million decrease in weather-normalized margins primarily in the eastern region.
    - A $20 million decrease for SWEPCo in municipal and cooperative revenues due to a true-up of formula rates in 2015.
    - An $11 million decrease for I&M in FERC municipal and cooperative revenues due to annual formula rate adjustments offset by increased formula rate changes.
- **Margins from Off-system Sales** decreased $19 million primarily due to lower market prices and decreased sales volumes.

- **Transmission Revenues** decreased $6 million primarily due to the following:
  - A $27 million decrease due to lower Network Integration Transmission Service (NITS) revenues.

  This decrease was partially offset by:
  - An $14 million increase in SPP Non-Affiliated Base Plan Funding associated with increased transmission investments. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - $5 million of SPP sponsor-funded transmission upgrades recorded in 2016. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
- **Other Revenues** increased $4 million primarily due to increased revenues from demand side management programs in Kentucky, partially offset within Other Operation and Maintenance below.

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

- **Other Operation and Maintenance** expenses increased $173 million primarily due to the following:
  - A $103 million increase in recoverable expenses, primarily including PJM, vegetation management, energy efficiency and storm expenses fully recovered in rate recovery riders/trackers within Retail Margins above.
  - A $57 million increase associated with amortization of deferred transmission costs in accordance with the Virginia Transmission Rate Adjustment Clause effective January 2016. This increase in expense is offset within Retail Margins above.
  - A $35 million increase due to a charitable donation to the AEP Foundation.
  - A $33 million increase in SPP and PJM transmission services expense.
  - A $6 million increase due to the reduction of an environmental liability in 2015 at I&M.

  These increases were partially offset by:
  - A $61 million decrease in plant outages, primarily planned outages in the eastern region.
  - A $6 million decrease due to a 2016 gain on the sale of property in the APCo region.
- **Asset Impairments and Other Related Charges** increased $11 million due to the impairment of I&M's Price River Coal reserves.
- **Depreciation and Amortization** expenses increased $11 million primarily due to:
  - A $42 million increase due to a higher depreciable base.

  These increases were partially offset by the following:
  - A $14 million decrease in the amortization of capitalized software due to retirements in 2015.
  - An $8 million decrease due to a revision in I&M's nuclear asset retirement obligation (ARO) estimate, which has a corresponding increase in Other Operation and Maintenance expenses above.
  - A $4 million decrease in amortization related to the advanced metering infrastructure projects in Oklahoma.
  - A $3 million decrease in ARO expenses due to steam plant retirements in 2015.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to an increase in property taxes as a result of increased property investment.
- **Allowance for Equity Funds Used During Construction** decreased $18 million primarily due to the completion of environmental projects at SWEPCo.
- **Interest Expense** increased $5 million primarily due to the following:
  - An $11 million increase due to higher long-term debt balances at I&M.

  This increase was partially offset by:
  - A $7 million decrease primarily due to the deferral of the debt component of carrying charges on environmental control costs for projects in Oklahoma at Northeastern Plant, Unit 3 and the Comanche Plant.
- **Income Tax Expense** decreased $52 million primarily due to the recording of federal and state income tax adjustments and other book/tax differences which are accounted for on a flow-through basis, partially offset by an increase in pretax book income.
- **Equity Earnings** increased $4 million primarily due to favorable tax adjustments in 2016.

2015 Compared to 2014

Reconciliation of Year Ended December 31, 2014 to Year Ended December 31, 2015
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2014	$ 707.6
Changes in Gross Margin:	
Retail Margins	377.6
Off-system Sales	(124.9)
Transmission Revenues	(26.4)
Other Revenues	1.3
Total Change in Gross Margin	227.6
Changes in Expenses and Other:	
Other Operation and Maintenance	(14.5)
Depreciation and Amortization	(29.6)
Taxes Other Than Income Taxes	(12.3)
Interest and Investment Income	1.2
Carrying Costs Income	5.1
Allowance for Equity Funds Used During Construction	16.9
Interest Expense	8.1
Total Change in Expenses and Other	(25.1)
Income Tax Expense	(15.8)
Equity Earnings	1.7
Net Income Attributable to Noncontrolling Interests	0.5
Year Ended December 31, 2015	$ 896.5

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

- **Retail Margins** increased $378 million primarily due to the following:
  - The effect of successful rate proceedings in AEP's service territories which included:
    - A $158 million increase primarily due to increases in rates in West Virginia, as well as an adjustment due to the amended Virginia law impacting biennial reviews.
    - An $88 million increase for I&M primarily due to rate increases from Indiana rate riders and annual FERC formula rate adjustments.
    - A $79 million increase for SWEPCo due to revenue increases from rate riders in Louisiana and Texas and increases in municipal and cooperative revenues due to annual FERC formula rate adjustments.
    - A $25 million increase for PSO primarily due to revenue increases from rate riders.

    For the increases described above, $70 million relate to riders/trackers which have corresponding increases in expense items below.
    - A $72 million decrease in Fuel and Purchased Electricity primarily due to the transfer of a one-half interest in the Mitchell Plant from AGR to WPCo in January 2015. This decrease was partially offset by increases in other expense items below.
    - A $32 million decrease in PJM charges not currently included in rate recovery riders/trackers.

  These increases were partially offset by:
    - A $70 million decrease in weather-normalized load primarily due to lower residential and industrial sales.
    - A $32 million decrease in weather-related usage primarily in the eastern region.
- **Margins from Off-system Sales** decreased $125 million primarily due to lower market prices and decreased sales volumes.
- **Transmission Revenues** decreased $26 million primarily due to decreased PJM revenues, partially offset by an increase in SPP margins.

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

- **Other Operation and Maintenance** expenses increased $15 million primarily due to the following:
    - A $56 million increase in recoverable expenses, primarily PJM expenses and vegetation management expenses currently fully recovered in rate recovery riders/trackers, partially offset by lower River Transportation Division (RTD) barging costs.
    - A $23 million increase in plant-related expenses primarily due to the transfer of a one-half interest in the Mitchell Plant from AGR to WPCo in January 2015. This increase was offset by an increase in Retail Margins above.
    - A $10 million increase in SPP and PJM transmission services.
    - A $4 million increase in regulatory commission expenses.

  These increases were partially offset by:
    - A $41 million decrease in employee-related expenses.
    - A $25 million decrease in vegetation management expenses not included in riders/trackers.
    - A $14 million decrease in environmental liabilities at I&M.
- **Depreciation and Amortization** expenses increased $30 million primarily due to overall higher depreciable base as well as amortization related to an advanced metering rider implemented in November 2014 in Oklahoma.
- **Taxes Other Than Income Taxes** increased $12 million primarily due to an increase in property taxes.
- **Allowance for Equity Funds Used During Construction** increased $17 million primarily due to increases in environmental and transmission projects.
- **Interest Expense** decreased $8 million primarily due to lower interest rates on APCo long-term debt.
- **Income Tax Expense** increased $16 million primarily due to an increase in pretax book income, partially offset by the recording of state and federal income tax adjustments and other book/tax differences which are accounted for on a flow-through basis.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Years Ended December 31, 2016	2015	2014
		(in millions)	
Revenues	$ 4,422.4	$ 4,556.6	$ 4,813.6
Purchased Electricity	837.1	1,144.2	1,676.5
Generation Deferrals	(82.7)	(30.7)	(157.0)
Amortization of Generation Deferrals	242.9	169.1	110.9
Gross Margin	3,425.1	3,274.0	3,183.2
Other Operation and Maintenance	1,386.7	1,328.9	1,276.1
Depreciation and Amortization	649.9	686.4	657.8
Taxes Other Than Income Taxes	494.3	478.3	453.4
Operating Income	894.2	780.4	795.9
Interest and Investment Income	14.8	6.4	10.1
Carrying Costs Income	20.0	11.8	26.5
Allowance for Equity Funds Used During Construction	15.1	15.5	11.7
Interest Expense	(256.9)	(276.2)	(280.3)
Income Before Income Tax Expense	687.2	537.9	563.9
Income Tax Expense	205.1	185.5	211.7
Net Income	482.1	352.4	352.2
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 482.1	$ 352.4	$ 352.2

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31, 2016	2015	2014
		(in millions of KWhs)	
Retail:			
Residential	26,191	25,735	26,209
Commercial	25,922	25,268	25,307
Industrial	22,179	22,353	21,830
Miscellaneous	700	702	713
Total Retail (a)	74,992	74,058	74,059
Wholesale (b)	1,888	1,701	2,198
Total KWhs	76,880	75,759	76,257

(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

	Years Ended December 31,		
	2016	**2015**	**2014**
	(in degree days)		
Eastern Region			
Actual – Heating (a)	2,957	3,235	3,734
Normal – Heating (b)	3,245	3,226	3,230
Actual – Cooling (c)	1,248	975	949
Normal – Cooling (b)	969	970	960
Western Region			
Actual – Heating (a)	201	390	428
Normal – Heating (b)	328	325	337
Actual – Cooling (d)	3,058	2,718	2,553
Normal – Cooling (b)	2,648	2,642	2,618

(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.

2016 Compared to 2015

Reconciliation of Year Ended December 31, 2015 to Year Ended December 31, 2016
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2015	$	352.4
Changes in Gross Margin:		
Retail Margins		185.4
Off-System Sales		46.3
Transmission Revenues		(0.6)
Other Revenues		(80.0)
Total Change in Gross Margin		151.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(57.8)
Depreciation and Amortization		36.5
Taxes Other Than Income Taxes		(16.0)
Interest and Investment Income		8.4
Carrying Costs Income		8.2
Allowance for Equity Funds Used During Construction		(0.4)
Interest Expense		19.3
Total Change in Expenses and Other		(1.8)
Income Tax Expense		(19.6)
Year Ended December 31, 2016	$	482.1

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

- **Retail Margins** increased $185 million primarily due to the following:
  - A $117 million increase in Ohio transmission and PJM revenues primarily due to the energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
  - An $83 million increase due to the impact of a 2016 regulatory deferral of capacity costs related to OPCo's December 2016 Global Settlement.
  - A $44 million increase in Ohio riders such as Universal Service Fund (USF) and *gridSMART®*. This increase in Retail Margins was primarily offset by an increase in Other Operation and Maintenance expenses below.
  - A $34 million increase in collections of PIRR carrying charges in Ohio as a result of the June 2016 PUCO order.
  - A $24 million increase in revenues associated with the Ohio Distribution Investment Rider (DIR). This increase was partially offset in various line items below.
  - A $22 million increase in AEP Texas weather-normalized margins primarily in the residential class.
  - A $20 million increase in AEP Texas revenues primarily due to the recovery of ERCOT transmission expenses, offset in Other Operation and Maintenance expenses below.
  - A $17 million increase in AEP Texas revenues primarily due to the recovery of distribution expenses.

  These increases were partially offset by:
  - A $150 million net decrease due to the impact of 2016 provisions for refund primarily related to OPCo's December 2016 Global Settlement.
  - A $16 million decrease in revenues associated with the recovery of 2012 storm costs under the Ohio Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins was primarily offset by a decrease in Other Operation and Maintenance expenses below.

- **Margins from Off-system Sales** increased $46 million primarily due to the following:
  - A $41 million increase due to a reversal of a 2015 provision for regulatory loss in Ohio.
  - An $8 million increase primarily due to prior year losses in Ohio from a power contract with OVEC.

  These increases were partially offset by:
  - A $3 million decrease in margins from a power contract with AEPEP for Oklaunion.
- **Transmission Revenues** decreased $1 million primarily due to the following:
  - A $56 million decrease in NITS revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.

  This decrease was partially offset by:
  - A $36 million increase primarily due to increased transmission investment in ERCOT.
  - A $19 million increase in Ohio due to a FERC settlement recorded in 2015 and FERC formula rate true-up adjustments.
- **Other Revenues** decreased $80 million primarily due to a decrease in Texas securitization revenue as a result of the final maturity of the first Texas securitization bond, offset in Depreciation and Amortization and other expense items below.

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

- **Other Operation and Maintenance** expenses increased $58 million primarily due to the following:
    - A $73 million increase in recoverable expenses, primarily including PJM expenses and *gridSMART*® expenses, currently fully recovered in rate recovery riders/trackers within Retail Margins above.
    - A $28 million increase due to charitable donations, including the AEP Foundation.
    - A $21 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.

  These increases were partially offset by:
    - A $14 million decrease due to the completion of the Ohio amortization of 2012 deferred storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
    - A $13 million decrease in distribution expenses primarily related to storms and 2015 asset inspections.
    - A $12 million decrease in vegetation management expenses.
    - A $12 million decrease related to a 2015 regulatory settlement in Ohio.
    - A $6 million decrease due to a PUCO ordered contribution to the Ohio Growth Fund recorded in 2015.
- **Depreciation and Amortization** expenses decreased $37 million primarily due to the following:
    - A $65 million decrease in the Texas securitization transition assets due to the final maturity of the first Texas securitization bond, which is offset in Other Revenues above.
    - A $7 million decrease in the amortization of capitalized software due to 2015 retirements.
    - A $4 million decrease in recoverable *gridSMART*® depreciation expenses in Ohio. This decrease was partially offset by a corresponding decrease in Retail Margins above.

  These decreases were partially offset by:
    - A $20 million increase in recoverable Ohio DIR depreciation expense. This increase was offset by a corresponding increase in Retail Margins above.
    - A $20 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
- **Taxes Other Than Income Taxes** increased $16 million primarily due to increased property taxes in Ohio resulting from additional investments in transmission and distribution assets and higher tax rates.
- **Interest and Investment Income** increased $8 million primarily due to a settlement with the IRS related to the U.K. Windfall Tax.
- **Carrying Costs Income** increased $8 million primarily due to the following:
    - A $14 million increase due to the impact of a 2016 regulatory deferral of carrying costs related to OPCo's December 2016 Global Settlement.
    - A $4 million increase primarily due to a 2015 unfavorable adjustment related to *gridSMART*® capital carrying charges in Ohio.

  These increases were partially offset by:
    - A $10 million decrease due to the collection of carrying costs on Ohio deferred capacity charges beginning June 2015.
- **Interest Expense** decreased $19 million primarily due to:
    - A $14 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.
    - A $12 million decrease due to the maturity of an OPCo senior unsecured note in June 2016.
    - A $2 million decrease in recoverable DIR interest expenses in Ohio. This decrease was offset by a corresponding decrease in Retail Margins above.

  These decreases were partially offset by the following:
    - An $11 million increase due to issuances of senior unsecured notes by AEP Texas.
- **Income Tax Expense** increased $20 million primarily due to an increase in pretax book income partially offset by the recording of state and federal income tax adjustments and the settlement of a 2011 audit issue with the IRS.

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2015 Compared to 2014

Reconciliation of Year Ended December 31, 2014 to Year Ended December 31, 2015
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2014	$	352.2
Changes in Gross Margin:		
Retail Margins		199.1
Off-System Sales		(28.5)
Transmission Revenues		(83.7)
Other Revenues		3.9
Total Change in Gross Margin		90.8
Changes in Expenses and Other:		
Other Operation and Maintenance		(52.8)
Depreciation and Amortization		(28.6)
Taxes Other Than Income Taxes		(24.9)
Interest and Investment Income		(3.7)
Carrying Costs Income		(14.7)
Allowance for Equity Funds Used During Construction		3.8
Interest Expense		4.1
Total Change in Expenses and Other		(116.8)
Income Tax Expense		26.2
Year Ended December 31, 2015	$	352.4

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

- **Retail Margins** increased $199 million primarily due to the following:
  - A $131 million increase in Ohio transmission and PJM revenues primarily due to energy supplied as a result of the Ohio auction and a regulatory change which resulted in revenues collected through a non-bypassable transmission rider, partially offset by a corresponding decrease in Transmission Revenues below.
  - A $50 million increase in Ohio rider revenues associated with the Distribution Investment Rider (DIR), the *gridSMART*® Rider, the Enhanced Service Reliability (ESR) Rider and the RSR. These increases in rider revenues are partially offset by net increases in other expense items below.
  - A $33 million negative Ohio regulatory provision recorded in 2014.
  - A $26 million increase in TCC and TNC revenues primarily due to the recovery of ERCOT transmission expenses, offset in Other Operation and Maintenance expenses below.

  These increases were partially offset by:
  - A $25 million decrease in revenues associated with the recovery of 2012 storm costs under the Ohio Storm Damage Recovery Rider which ended in April 2015. This decrease in Retail Margins is offset by a decrease in Other Operation and Maintenance expenses below.
  - A $17 million decrease in Ohio Energy Efficiency/Peak Demand Reduction (EE/PDR) Rider revenues. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
  - An $11 million decrease in revenues associated with the Universal Service Fund (USF) surcharge. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
- **Margins from Off-system Sales** decreased $29 million primarily due to losses from a legacy OPCo power contract.

- **Transmission Revenues** decreased $84 million primarily due to the following:
  - An $80 million decrease in PJM Network Integrated Transmission Service (NITS) revenue primarily due to OPCo assuming the responsibility for items determined to be cost-based transmission-related charges that were the responsibility of the CRES providers prior to June 2015, partially offset by a corresponding increase in Retail Margins above.
  - A $12 million decrease in Ohio revenues related to a lower annual transmission formula rate true-up.
  - A $9 million OPCo transmission regulatory settlement in 2015.

  These decreases were partially offset by:
  - A $25 million increase primarily due to increased transmission investment in ERCOT.

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

- **Other Operation and Maintenance** expenses increased $53 million primarily due to the following:
  - A $72 million increase in recoverable PJM, ERCOT and *gridSMART*® expenses. These increases were offset by increases in Retail Margins above.
  - A $19 million increase in distribution expenses including system improvements and storm expenses.
  - A $12 million increase related to a regulatory settlement in Ohio.
  - A $6 million increase due to PUCO ordered contributions to the Ohio Growth Fund.

  These increases were partially offset by:
  - A $26 million decrease due to the completion of the amortization of 2012 deferred storm expenses in April 2015. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $17 million decrease in EE/PDR costs and associated deferrals. This decrease was offset by a corresponding decrease in Retail Margins above.
  - An $11 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.
- **Depreciation and Amortization** expenses increased $29 million primarily due to the following:
  - A $29 million increase due to an increase in the depreciable base of transmission and distribution assets.
  - An $8 million increase in amortization of TCC's securitization transition asset, partially offset in Other Revenues.
  - An $8 million increase in amortization expenses for the collection of carrying costs on deferred capacity charges beginning June 2015. This increase was offset by a corresponding increase in Retail Margins above.

  These increases were partially offset by:
  - A $9 million decrease in recoverable DIR depreciation expense. This decrease was offset by a decrease in Retail Margins above.
  - An $8 million decrease in recoverable *gridSMART*® depreciation expense. This decrease was offset by a decrease in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $25 million primarily due to increased property taxes.
- **Interest and Investment Income** decreased $4 million primarily due to a decrease in affiliated notes payable for OPCo. This decrease was offset by a decrease in Interest Expense.
- **Carrying Costs Income** decreased $15 million primarily due to the collection of carrying costs on deferred capacity charges beginning June 2015.
- **Income Tax Expense** decreased $26 million primarily due to a decrease in pretax book income and by the recording of state income tax adjustments.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Years Ended December 31, 2016	2015	2014
		(in millions)	
Transmission Revenues	$ 512.8	$ 329.2	$ 191.9
Other Operation and Maintenance	55.3	38.4	28.7
Depreciation and Amortization	67.1	43.0	23.7
Taxes Other Than Income Taxes	88.7	66.0	31.8
Operating Income	301.7	181.8	107.7
Interest and Investment Income	0.4	0.2	—
Carrying Costs Expense	(0.3)	(0.2)	—
Allowance for Equity Funds Used During Construction	52.2	53.0	44.8
Interest Expense	(50.3)	(37.2)	(23.5)
Income Before Income Tax Expense and Equity Earnings	303.7	197.6	129.0
Income Tax Expense	134.1	91.3	62.9
Equity Earnings of Unconsolidated Subsidiaries	99.7	86.4	84.7
Net Income	269.3	192.7	150.8
Net Income Attributable to Noncontrolling Interests	3.0	1.5	—
Earnings Attributable to AEP Common Shareholders	$ 266.3	$ 191.2	$ 150.8

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

	December 31, 2016	2015	2014
		(in millions)	
Net Plant In Service	$ 4,284.6	$ 2,832.7	$ 1,800.8
CWIP	968.0	1,092.6	888.9

2016 Compared to 2015

Reconciliation of Year Ended December 31, 2015 to Year Ended December 31, 2016
Earnings Attributable to AEP Common Shareholders from Transmission Holdco
(in millions)

Year Ended December 31, 2015	$	191.2
Changes in Transmission Revenues:		
Transmission Revenues		183.6
Total Change in Transmission Revenues		183.6
Changes in Expenses and Other:		
Other Operation and Maintenance		(16.9)
Depreciation and Amortization		(24.1)
Taxes Other Than Income Taxes		(22.7)
Interest and Investment Income		0.2
Carrying Costs Income		(0.1)
Allowance for Equity Funds Used During Construction		(0.8)
Interest Expense		(13.1)
Total Change in Expenses and Other		(77.5)
Income Tax Expense		(42.8)
Equity Earnings		13.3
Net Income Attributable to Noncontrolling Interests		(1.5)
Year Ended December 31, 2016	$	266.3

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 $184 million primarily due to the following:
  - A $156 million increase due to formula rate increases driven by continued investment in transmission assets and the related increases in recoverable operating expenses.
  - A $28 million increase due to annual formula rate true-up adjustments.

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

- **Other Operation and Maintenance** expenses increased $17 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $24 million primarily due to higher depreciable base.
- **Taxes Other Than Income Taxes** increased $23 million primarily due to increased property taxes as a result of additional transmission investment.
- **Interest Expense** increased $13 million primarily due to higher outstanding long-term debt balances.
- **Income Tax Expense** increased $43 million primarily due to an increase in pretax book income.
- **Equity Earnings** increased $13 million primarily due to increased transmission investment by ETT.

2015 Compared to 2014

**Reconciliation of Year Ended December 31, 2014 to Year Ended December 31, 2015
Earnings Attributable to AEP Common Shareholders from Transmission Holdco
(in millions)**

Year Ended December 31, 2014	$ 150.8
Changes in Transmission Revenues:	
Transmission Revenues	137.3
Total Change in Transmission Revenues	137.3
Changes in Expenses and Other:	
Other Operation and Maintenance	(9.7)
Depreciation and Amortization	(19.3)
Taxes Other Than Income Taxes	(34.2)
Interest and Investment Income	0.2
Carrying Costs Income	(0.2)
Allowance for Equity Funds Used During Construction	8.2
Interest Expense	(13.7)
Total Change in Expenses and Other	(68.7)
Income Tax Expense	(28.4)
Equity Earnings	1.7
Net Income Attributable to Noncontrolling Interests	(1.5)
Year Ended December 31, 2015	$ 191.2

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 $137 million primarily due to an increase in projects placed in-service by AEP's wholly-owned transmission subsidiaries.

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

- **Other Operation and Maintenance** expenses increased $10 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $19 million primarily due to higher depreciable base.
- **Taxes Other Than Income Taxes** increased $34 million primarily due to increased property taxes.
- **Allowance for Equity Funds Used During Construction** increased $8 million primarily due to increased transmission investment.
- **Interest Expense** increased $14 million primarily due to higher outstanding long-term debt balances.
- **Income Tax Expense** increased $28 million primarily due to an increase in pretax book income.

GENERATION & MARKETING

Generation & Marketing	Years Ended December 31, 2016	2015	2014
		(in millions)	
Revenues	$ 2,986.0	$ 3,412.7	$ 3,849.6
Fuel, Purchased Electricity and Other	1,948.6	2,164.6	2,436.3
Gross Margin	1,037.4	1,248.1	1,413.3
Other Operation and Maintenance	418.4	408.4	549.7
Asset Impairments and Other Related Charges	2,257.3	—	—
Depreciation and Amortization	154.6	201.4	226.8
Taxes Other Than Income Taxes	37.6	40.7	49.6
Operating Income (Loss)	(1,830.5)	597.6	587.2
Interest and Investment Income	1.4	2.8	4.7
Allowance for Equity Funds Used During Construction	0.4	0.2	0.1
Interest Expense	(35.8)	(40.0)	(45.3)
Income (Loss) Before Income Tax Expense	(1,864.5)	560.6	546.7
Income Tax Expense (Credit)	(666.5)	194.6	179.3
Net Income (Loss)	(1,198.0)	366.0	367.4
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings (Loss) Attributable to AEP Common Shareholders	$ (1,198.0)	$ 366.0	$ 367.4

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31, 2016	2015	2014
		(in millions of MWhs)	
Fuel Type:			
Coal	25	27	38
Natural Gas	14	13	7
Wind	1	1	1
Total MWhs	40	41	46

2016 Compared to 2015

Reconciliation of Year Ended December 31, 2015 to Year Ended December 31, 2016
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2015	$	366.0
Changes in Gross Margin:		
Generation		(224.9)
Retail, Trading and Marketing		17.7
Other		(3.5)
Total Change in Gross Margin		(210.7)
Changes in Expenses and Other:		
Other Operation and Maintenance		(10.0)
Asset Impairments and Other Related Charges		(2,257.3)
Depreciation and Amortization		46.8
Taxes Other Than Income Taxes		3.1
Interest and Investment Income		(1.4)
Allowance for Equity Funds Used During Construction		0.2
Interest Expense		4.2
Total Change in Expenses and Other		(2,214.4)
Income Tax Expense		861.1
Year Ended December 31, 2016	$	(1,198.0)

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 $225 million primarily due to reduced power prices, lower capacity revenues resulting from plant retirements, and the transition of the Ohio SSO to full market pricing, partially offset by favorable hedging activity.
- **Retail, Trading and Marketing** increased $18 million primarily due to an increase in retail volumes and increased margins.
- **Other Revenue** decreased $4 million primarily due to unfavorable wind conditions and decreased wholesale energy prices.

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

- **Other Operation and Maintenance** expenses increased $10 million primarily due to the 2015 sale of certain assets and revision of the related asset retirement obligations, partially offset by a decrease in maintenance due to plant retirements in June 2015.
- **Asset Impairments and Other Related Charges** increased $2.3 billion due to an asset impairment of certain merchant generation assets.
- **Depreciation and Amortization** decreased $47 million primarily due to the impairment of certain merchant generation assets, the classification of certain assets as held for sale and plant retirements in June 2015.
- **Interest Expense** decreased $4 million primarily due to a decrease in long-term debt outstanding.
- **Income Tax Expense** decreased $861 million primarily due to reduced pretax book income as a result of the impairment of certain merchant generation assets and by the recording of federal and state income tax adjustments.

2015 Compared to 2014

Reconciliation of Year Ended December 31, 2014 to Year Ended December 31, 2015
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2014	$ 367.4
Changes in Gross Margin:	
Generation	(203.9)
Retail, Trading and Marketing	43.2
Other	(4.5)
Total Change in Gross Margin	(165.2)
Changes in Expenses and Other:	
Other Operation and Maintenance	141.3
Depreciation and Amortization	25.4
Taxes Other Than Income Taxes	8.9
Interest and Investment Income	(1.9)
Allowance for Equity Funds Used During Construction	0.1
Interest Expense	5.3
Total Change in Expenses and Other	179.1
Income Tax Expense	(15.3)
Year Ended December 31, 2015	$ 366.0

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 $204 million primarily due to lower capacity revenue due to the termination of the Power Supply Agreement between AGR and OPCo in May 2015.
- **Retail, Trading and Marketing** increased $43 million primarily due to favorable wholesale trading and marketing performance as well as an increase in retail volumes.

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

- **Other Operation and Maintenance** expenses decreased $141 million primarily due to a settlement and revision of certain asset retirement obligations and decreased plant outage and maintenance costs.
- **Depreciation and Amortization** expenses decreased $25 million primarily due to reduced plant in-service.
- **Taxes Other Than Income Taxes** decreased $9 million primarily due to a decrease in property taxes.
- **Interest Expense** decreased $5 million primarily due to lower outstanding debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $15 million primarily due to an increase in pretax book income and by the recording of federal and state income tax adjustments.

CORPORATE AND OTHER

2016 Compared to 2015

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from $241 million in 2015 to $81 million in 2016 primarily due to the reversal of capital loss valuation allowances related to the settlement of 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. This was partly offset by the gain on the sale of AEP River Operations, charges related to the final accounting of the disposition of AEP's commercial barging operations and decreased income from the discontinued operations of AEP's commercial barging operations which was sold in November 2015.

2015 Compared to 2014

Earnings attributable to AEP Common Shareholders from Corporate and Other increased from $56 million in 2014 to $241 million in 2015 primarily due to the gain on the sale of AEP River Operations that was recorded in Income from Discontinued Operations, Net of Tax, on the statement of income.

AEP SYSTEM INCOME TAXES

2016 Compared to 2015

Income Tax Expense decreased $993 million primarily due to reduced pretax book income as a result of the impairment of certain merchant generation assets, the reversal of capital loss valuation allowances related to the pending sale of certain merchant generation assets and the settlement of a 2011 audit issue with the IRS as well as 2015 tax return adjustments related to the disposition of AEP's commercial barging operations.

2015 Compared to 2014

Income Tax Expense increased $17 million primarily due to an increase in pretax book income, partially offset by the recording of state income tax adjustments and other book/tax differences which are accounted for on a flow-through basis.

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

	December 31,				
	2016			2015	
	(dollars in millions)				
Long-term Debt, including amounts due within one year	$ 20,391.2	(a)	51.6%	$ 19,572.7	51.1%
Short-term Debt	1,713.0		4.3	800.0	2.1
Total Debt	22,104.2	(a)	55.9	20,372.7	53.2
AEP Common Equity	17,397.0		44.0	17,891.7	46.8
Noncontrolling Interests	23.1		0.1	13.2	—
Total Debt and Equity Capitalization	$ 39,524.3		100.0%	$ 38,277.6	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 7 for additional information.

AEP's ratio of debt-to-total capital changed primarily due to an increase in debt related to increased construction expenditures in AEP Transmission Holdco, offset by a decrease in common equity as a result of the impairment of certain merchant generation assets.

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 December 31, 2016, AEP had $3.5 billion in aggregate credit facility commitments to support its operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

AEP manages liquidity by maintaining adequate external financing commitments. As of December 31, 2016, available liquidity was approximately $2.7 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 3,000.0	June 2021
Revolving Credit Facility	500.0	June 2018
Total	3,500.0	
Cash and Cash Equivalents	210.5	
Total Liquidity Sources	3,710.5	
Less: AEP Commercial Paper Outstanding	1,040.0	
Net Available Liquidity	$ 2,670.5	

AEP has credit facilities totaling $3.5 billion to support its commercial paper program. The $3 billion credit facility allows management to issue letters of credit in an amount up to $1.2 billion.

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2016 was $1.5 billion. The weighted-average interest rate for AEP's commercial paper during 2016 was 0.80%.

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 four uncommitted facilities totaling $300 million. As of December 31, 2016, the maximum future payments for letters of credit issued under the uncommitted facilities was $150 million with maturities ranging from January 2017 to February 2018.

Financing Plan

As of December 31, 2016, AEP has $3 billion of long-term debt due within one year which includes $458 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current. Management plans to refinance the majority of the other maturities due within one year. Also included in AEP's long-term debt due within one year is $423 million of securitization bonds and DCC Fuel notes.

Securitized Accounts Receivables

AEP's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement expires in June 2018.

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 December 31, 2016, this contractually-defined percentage was 53.6%. 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 facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders and AEP manages its borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.59 per share in January 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.

	Years Ended December 31, 2016	2015	2014
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 176.4	$ 162.5	$ 117.5
Net Cash Flows from Continuing Operating Activities	4,521.8	4,748.7	4,602.4
Net Cash Flows Used for Continuing Investing Activities	(4,989.1)	(4,564.0)	(4,405.9)
Net Cash Flows from (Used for) Continuing Financing Activities	503.9	(661.7)	(150.9)
Net Cash Flows from (Used for) Discontinued Operations	(2.5)	490.9	(0.6)
Net Increase in Cash and Cash Equivalents	34.1	13.9	45.0
Cash and Cash Equivalents at End of Period	$ 210.5	$ 176.4	$ 162.5

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

	Years Ended December 31, 2016	2015	2014
		(in millions)	
Income from Continuing Operations	$ 620.5	$ 1,768.6	$ 1,590.5
Depreciation and Amortization	1,962.3	2,009.7	1,897.6
Deferred Income Taxes	(50.0)	808.2	868.8
Asset Impairments and Other Related Charges	2,267.8	—	—
Deferred Fuel Over/Under-Recover, Net	(65.5)	137.8	(35.5)
Disposition of Tanners Creek Plant Site	(93.5)	—	—
Fuel, Materials and Supplies	60.2	(38.6)	100.8
Accrued Taxes, Net	42.8	120.2	0.4
Other	(222.8)	(57.2)	179.8
Net Cash Flows from Continuing Operating Activities	$ 4,521.8	$ 4,748.7	$ 4,602.4

Net Cash Flows from Continuing Operating Activities were $4.5 billion in 2016 consisting primarily of Income from Continuing Operations of $621 million and $2 billion of noncash Depreciation and Amortization. AEP also had asset impairments of $2.3 billion during the third quarter of 2016. AEP sold its retired Tanners Creek plant site, including its associated asset retirement obligations to a nonaffiliated party. See Note 7 - Dispositions, Assets and Liabilities Held for Sale and Impairments for a complete discussion of dispositions, 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. Over/Under Fuel decreased primarily due to updated fuel rates at PSO. 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 $4.7 billion in 2015 consisting primarily of Income from Continuing Operations of $1.8 billion and $2 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Protecting Americans from Tax Hikes Act of 2015 and an increase in tax versus book temporary differences from operations.

Net Cash Flows from Continuing Operating Activities were $4.6 billion in 2014 consisting primarily of Income from Continuing Operations of $1.6 billion and $1.9 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Tax Increase Prevention Act of 2014 and an increase in tax versus book temporary differences from operations. The reduction in Fuel, Material and Supplies balance reflects a decrease in fuel inventory due to cold winter weather and increased generation.

Investing Activities

	Years Ended December 31,		
	2016	2015	2014
		(in millions)	
Construction Expenditures	$ (4,781.1)	$ (4,508.0)	$ (4,130.0)
Acquisitions of Nuclear Fuel	(128.5)	(92.0)	(116.2)
Acquisitions of Assets/Businesses	(107.9)	(5.3)	(64.8)
Other	28.4	41.3	(94.9)
Net Cash Flows Used for Continuing Investing Activities	$ (4,989.1)	$ (4,564.0)	$ (4,405.9)

Net Cash Flows Used for Continuing Investing Activities were $5 billion in 2016 primarily due to Construction Expenditures for generation, distribution and transmission investments. AEP also purchased solar assets for $102 million.

Net Cash Flows Used for Continuing Investing Activities were $4.6 billion in 2015 primarily due to Construction Expenditures for generation, distribution and transmission investments.

Net Cash Flows Used for Continuing Investing Activities were $4.4 billion in 2014 primarily due to Construction Expenditures for generation, distribution and transmission investments. AEP also purchased transmission assets for $38 million.

Financing Activities

	Years Ended December 31,		
	2016	2015	2014
		(in millions)	
Issuance of Common Stock, Net	$ 34.2	$ 81.6	$ 73.6
Issuance/Retirement of Debt, Net	1,713.0	492.7	878.6
Dividends Paid on Common Stock	(1,121.0)	(1,059.0)	(997.6)
Other	(122.3)	(177.0)	(105.5)
Net Cash Flows from (Used for) Continuing Financing Activities	$ 503.9	$ (661.7)	$ (150.9)

Net Cash Flows from Continuing Financing Activities in 2016 were $504 million. AEP's net debt issuances were $1.7 billion. The net issuances included issuances of $1.7 billion of senior unsecured notes, $191 million of pollution control bonds, $779 million of other debt notes and an increase in short-term borrowing of $913 million offset by retirements of $807 million of senior unsecured notes, $323 million of securitization bonds, $251 million of pollution control bonds and $414 million of other debt notes. AEP paid common stock dividends of $1.1 billion. See Note 14 – Financing Activities.

Net Cash Flows Used for Continuing Financing Activities in 2015 were $662 million. AEP's net debt issuances were $493 million. The net issuances included issuances of $2.1 billion of senior unsecured notes, $140 million of pollution control bonds and $1.2 billion of other debt notes offset by retirements of $1 billion of senior unsecured notes, $342 million of securitization bonds, $308 million of pollution control bonds and $716 million of other debt notes and a decrease in short term borrowing of $546 million. AEP paid common stock dividends of $1.1 billion. See Note 14 – Financing Activities.

Net Cash Flows Used for Continuing Financing Activities in 2014 were $151 million. AEP's net debt issuances were $879 million. The net issuances included issuances of $1.6 billion of senior unsecured notes and other debt notes, $444 million of pollution control bonds and an increase in short-term borrowing of $589 million offset by retirements of $1.1 billion of notes, $412 million of pollution control bonds and $306 million of securitization bonds. AEP paid common stock dividends of $998 million. See Note 14 – Financing Activities.

The following financing activities occurred during 2016:

AEP Common Stock:

- During 2016, AEP issued 659 thousand shares of common stock under the incentive compensation, employee saving and dividend reinvestment plans and received net proceeds of $34 million.

Debt:

- During 2016, AEP issued approximately $2.6 billion of long-term debt, including $1.7 billion of senior notes at interest rates ranging from 2.75% to 4.55%, $191 million of pollution control revenue bonds and $779 million of other debt at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and construction programs.
- During 2016, AEP did not enter into any interest rate derivatives and settled $60 million of such transactions. The settlements resulted in net cash received of $582 thousand. As of December 31, 2016, AEP had in place $500 million of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2017:

- In January and February 2017, I&M retired $20 million and $7 million, respectively, of Notes Payable related to DCC Fuel.
- In January 2017, APCo retired $104 million of variable rate Pollution Control Bonds.
- In January 2017, OPCo retired $22 million of Securitization Bonds.
- In January 2017, SWEPCo retired $250 million of Senior Unsecured Notes.
- In January 2017, AEP Texas retired $90 million of Securitization Bonds.
- In January 2017, AGR retired $500 million of Other Long-term Debt.
- In February 2017, APCo retired $12 million of Securitization Bonds.
- In February 2017, SWEPCo retired $2 million of Other Long-term Debt.

Cash Flow Activity from Discontinued Operations

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015 and resulted in net cash proceeds from the sale of $491 million, which were immediately available for use in AEP's continuing operations. The cash proceeds of $539 million were recorded in Discontinued Investing Activities. These proceeds were reduced by a make whole payment on the extinguishment of AEPRO long-term debt of $32 million, which was recorded in Discontinued Financing Activities, and transaction costs of $16 million, which were recorded in Discontinued Operating Activities. In the second quarter of 2016, AEP recorded a $3 million loss related to the final accounting for the sale of AEPRO, which was also recorded in Discontinued Operating Activities. See "AEPRO (Corporate and Other)" section of Note 7 for additional information.

BUDGETED CONSTRUCTION EXPENDITURES

Management forecasts approximately $5.7 billion of construction expenditures in 2017. For 2018 and 2019 combined, management forecasts construction expenditures of $11.6 billion. The expenditures are generally for transmission, generation, distribution and required environmental investment to comply with the Federal EPA rules. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. Management expects to fund these construction expenditures through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2017 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2017 Budgeted Construction Expenditures					
Segment	Environmental	Generation	Transmission	Distribution	Other	Total
			(in millions)			
Vertically Integrated Utilities	$ 203.2	$ 496.4	$ 653.2	$ 756.3	$ 191.9	$ 2,301.0
Transmission and Distribution Utilities	0.1	1.5	812.7	597.6	186.3	1,598.2
AEP Transmission Holdco	—	—	1,473.5	—	32.7	1,506.2
Generation & Marketing	23.4	278.0	—	—	15.2	316.6
Corporate and Other	—	—	—	—	(55.8)	(55.8)
Total	$ 226.7	$ 775.9	$ 2,939.4	$ 1,353.9	$ 370.3	$ 5,666.2

The 2017 estimated construction expenditures by Registrant Subsidiary include distribution, transmission and generation related investments, as well as expenditures for compliance with environmental regulations as follows:

	2017 Budgeted Construction Expenditures					
Company	Environmental	Generation	Transmission	Distribution	Other	Total
			(in millions)			
APCo	$ 44.2	$ 129.9	$ 300.1	$ 234.2	$ 66.1	$ 774.5
I&M	57.9	212.2	98.3	221.9	46.3	636.6
OPCo	—	—	130.4	337.0	78.8	546.2
PSO	0.3	37.3	47.9	137.5	28.3	251.3
SWEPCo	22.9	85.7	173.3	99.4	36.5	417.8

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.

Rockport Plant, Unit 2

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for AEGCo and I&M are $443 million each as of December 31, 2016.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. AEP's subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, as well as AEP's subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, AEP entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. AEP intends to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $19 million for the remaining railcars as of December 31, 2016. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five-year renewal. As of December 31, 2016, the maximum potential loss was approximately $18 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss. AEP has other railcar lease arrangements that do not utilize this type of financing structure.

CONTRACTUAL OBLIGATION INFORMATION

AEP's contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in the footnotes. The following table summarizes AEP's contractual cash obligations as of December 31, 2016:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 1,713.0	$ —	$ —	$ —	$ 1,713.0
Interest on Fixed Rate Portion of Long-term Debt (b)	900.9	1,603.2	1,400.3	8,794.2	12,698.6
Fixed Rate Portion of Long-term Debt (c)	1,904.0	3,165.7	1,786.8	11,437.3	18,293.8
Variable Rate Portion of Long-term Debt (d)	1,109.4	1,108.4	8.0	—	2,225.8
Capital Lease Obligations (e)	81.3	113.7	72.1	118.7	385.8
Noncancelable Operating Leases (e)	238.2	450.5	410.3	282.2	1,381.2
Fuel Purchase Contracts (f) (g)	1,387.8	1,478.5	1,040.7	458.2	4,365.2
Energy and Capacity Purchase Contracts	215.5	437.1	439.1	1,740.2	2,831.9
Construction Contracts for Capital Assets (h) (i)	1,689.5	1,623.8	742.9	1,552.1	5,608.3
Total	$ 9,239.6	$ 9,980.9	$ 5,900.2	$ 24,382.9	$ 49,503.6

(a) Represents principal only, excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14. Represents principal only, excluding interest.
(d) See "Long-term Debt" section of Note 14. Represents principal only, excluding interest. Variable rate debt had interest rates that ranged between 0.68% and 2.57% as of December 31, 2016.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Excludes approximately $1.1 billion of fuel purchase contracts related to plants Held for Sale. See Note 7.
(h) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.
(i) Excludes approximately $20 million of construction contracts for capital assets related to plants Held for Sale. See Note 7.

AEP's $49 million liability related to uncertain tax positions is not included above because management cannot reasonably estimate the cash flows by period.

AEP's pension funding requirements are not included in the above table. As of December 31, 2016, AEP expects to make contributions to the pension plans totaling $98 million in 2017. Estimated contributions of $90 million in 2018 and $91 million in 2019 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, the pension plans were 94.9% funded as of December 31, 2016. See "Estimated Future Benefit Payments and Contributions" section of Note 8.

In addition to the amounts disclosed in the contractual cash obligations table above, additional commitments are made in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. As of December 31, 2016, the commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Standby Letters of Credit (a)	$ 130.9	$ 18.8	$ —	$ —	$ 149.7
Guarantees of the Performance of Outside Parties (b)	—	—	—	115.0	115.0
Guarantees of Performance (c)	1,159.9	—	—	—	1,159.9
Total Commercial Commitments	$ 1,290.8	$ 18.8	$ —	$ 115.0	$ 1,424.6

(a) Standby letters of credit (LOCs) are entered into with third parties. These LOCs are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. There is no collateral held in relation to any guarantees in excess of the ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. See "Letters of Credit" section of Note 6.
(b) See "Guarantees of Third-Party Obligations" section of Note 6.
(c) Performance guarantees and indemnifications issued for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

The Tax Increase Prevention Act of 2014 provided for a one-year extension of the 50% bonus depreciation and for the extension of research and development, employment and several energy tax credits for 2014.

The Protecting Americans from Tax Hikes Act of 2015 (PATH) included an extension of the 50% bonus depreciation for three years through 2017, phasing down to 40% in 2018 and 30% in 2019. PATH also provided for the extension of research and development, employment and several energy tax credits for 2015. PATH also includes provisions to extend the wind energy production tax credit through 2016 with a three-year phase-out (2017-2019), and to extend the 30% temporary solar investment tax credit for three years through 2019 with a two-year phase-out (2020-2021). PATH also provided for a permanent extension of the Research and Development tax credit.

These enacted provisions had no material impact on net income or financial condition but did have a favorable impact on cash flows in 2014, 2015 and 2016 and are expected to have a favorable impact on future cash flows.

Federal Tax Reform

Management is evaluating the possibility of federal tax reform. While there is no proposed statutory tax language on which to base definitive conclusions, management reviewed the tax proposals currently available, particularly the House Republican Blueprint. Management has assessed the accumulated deferred federal income taxes on the balance sheet as of December 31, 2016 and identified approximately $4 billion in potential excess accumulated deferred federal income taxes based on an assumed 20% federal tax rate. Based upon the last major tax reform initiative in 1986, management believes that approximately $3 billion of the excess accumulated deferred income tax related to depreciation would flow back to customers through lower rates over the life of the applicable property, while the remaining $1 billion would flow back to customers through lower rates over a negotiated period of years as determined through the regulatory process. Management continues to work with industry groups and legislators to advocate for the benefit of AEP's customers and shareholders.

CYBER SECURITY

Cyber security presents a growing risk for electric utility systems because a cyber-attack could affect critical energy infrastructure. Breaches to the cyber security of the grid or to the AEP System are potentially disruptive to people, property and commerce and create risk for business, investors and customers. In February 2013, President Obama signed an executive order that addresses how government agencies will operate and support their functions in cyber security as well as redefines how the government interfaces with critical infrastructure, such as the electric grid. The AEP System already operates under regulatory cyber security standards to protect critical infrastructure. The cyber security framework that was being developed through this executive order was reviewed by FERC and the U.S. Department of Energy (DOE). In 2014, the DOE published an Energy Sector Cyber Security Framework Implementation Guide for utilities to use in adopting and implementing the National Institute of Standards and Technology framework. AEP continues to be actively engaged in the framework process.

The electric utility industry is one of the few critical infrastructure functions with mandatory cyber security requirements under the authority of FERC. The Energy Policy Act of 2005 gave FERC the authority to oversee reliability of the bulk power system, including the authority to implement mandatory cyber security reliability standards. The North American Electric Reliability Corporation (NERC), which FERC certified as the nation's Electric Reliability Organization, developed mandatory critical infrastructure protection cyber security reliability standards. AEP participated in the NERC grid security and emergency response exercises, GridEx, in 2013 and 2015. These efforts, led by NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

Critical cyber assets, such as data centers, power plants, transmission operations centers and business networks are protected using multiple layers of cyber security and authentication. The AEP System is constantly scanned for risks or threats. Cyber hackers have been able to breach a number of very secure facilities, from federal agencies, banks and retailers to social media sites. As these events become known and develop, AEP continually assesses its cyber security tools and processes to determine where to strengthen its defenses. Management continually reviews its business continuity plan to develop an effective recovery effort that decreases response times, limits financial impacts and maintains customer confidence following any business interruption. Management works closely with a broad range of departments, including Legal, Regulatory, Corporate Communications, Audit Services, Information Technology and Security, to ensure the corporate response to consequences of any breach or potential breach is appropriate both for internal and external audiences based on the specific circumstances surrounding the event.

Management continues to take steps to enhance the AEP System's capabilities for identifying risks or threats and has shared that knowledge of threats with utility peers, industry and federal agencies. AEP operates a Cyber Security Intelligence and Response Center responsible for monitoring the AEP System for cyber threats as well as collaborating with internal and external threat sharing partners from both industry and government. AEP is a member of a number of industry specific threat and information sharing communities including the Department of Homeland Security and the Electricity Information Sharing and Analysis Center.

AEP has partnered in the past with a major defense contractor who has significant cyber security experience and technical capabilities developed through their work with the U.S. Department of Defense. AEP works with a consortium of other utilities across the country, learning how best to share information about potential threats and collaborating with each other. AEP continues to work with a nonaffiliated entity to conduct several discussions each year about recognizing and investigating cyber vulnerabilities. Through these types of efforts, AEP is working to protect itself while helping its industry advance its cyber security capabilities.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about AEP's critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

The Registrants recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, the timing of expense and income recognition is matched with regulated revenues. Liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, regulatory assets are recorded on the balance sheet. Management reviews the probability of recovery at each balance sheet date and whenever new events occur. Similarly, regulatory liabilities are recorded when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. Refer to Note 5 for further detail related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

AEP records revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. PSO and SWEPCo do not record the fuel portion of unbilled revenue in accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas.

Accrued unbilled revenues for the Vertically Integrated Utilities segment were $241 million and $191 million as of December 31, 2016 and 2015, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $50 million, $(63) million and $(29) million for the years ended December 31, 2016, 2015 and 2014, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $191 million and $151 million as of December 31, 2016 and 2015, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $40 million, $(30) million and $16 million for the years ended December 31, 2016, 2015 and 2014, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Generation & Marketing segment were $49 million and $47 million as of December 31, 2016 and 2015, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $2 million, $(3) million and $9 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Assumptions and Approach Used

For each Registrant, the monthly estimate for unbilled revenues is based upon a primary computation of net generation (generation plus purchases less sales) less the current month's billed KWh and estimated line losses, plus the prior month's unbilled KWh. However, due to meter reading issues, meter drift and other anomalies, a secondary computation is made, based upon an allocation of billed KWh to the current month and previous month, on a billing cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWh. The two methodologies are evaluated to confirm that they are not statistically different.

For AEP's Generation & Marketing segment, management calculates unbilled revenues by contract using the most recent historic daily activity adjusted for significant known changes in usage.

Effect if Different Assumptions Used

If the two methodologies used to estimate unbilled revenue are statistically different, a limiter adjustment is made to bring the primary computation within one standard deviation of the secondary computation. Additionally, significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the estimate of unbilled revenue.

Accounting for Derivative Instruments

Nature of Estimates Required

Management considers fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

The Registrants measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

The Registrants reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments on risk management contracts are calculated using estimated default probabilities and recovery rates relative to the counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, management assesses hedge effectiveness and evaluates a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the Registrants evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable including planned abandonments and a probable disallowance for rate-making on a plant under construction or the assets meet the held-for-sale criteria. The Registrants utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived, held and used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, the Registrants record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, the earnings impact of an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery is probable. For competitive generation assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, the Registrants estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions on the use of the asset. The Registrants perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for cost-based regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of the asset can vary if different estimates and assumptions would have been used in the applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, the best estimate of fair value was made using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

AEP maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). Additionally, AEP entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. AEP also sponsors other postretirement benefit plans to provide health and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively referred to as the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost (credit) of the Plans:

Net Periodic Cost (Credit)	Years Ended December 31, 2016	2015	2014
		(in millions)	
Pension Plans	$ 103.2	$ 133.3	$ 157.8
Postretirement Plans	(73.5)	(92.3)	(76.8)

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2017, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets and tax rates which affect a portion of the Postretirement Plans' assets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 6% for the Qualified Plan and 6.75% for the Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on management's targeted asset allocation and expected investment returns for each investment category. Assumptions for the Plans are summarized in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	2017 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2017 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	25%	8.55%	65%	7.88%
Fixed Income	59	4.65	33	4.54
Other Investments	15	8.03	—	—
Cash and Cash Equivalents	1	3.30	2	3.30
Total	100%		100%	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 6% for the Qualified Plan and 6.75% for the Postretirement Plans are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 6.98% and 0.8% for the years ended December 31, 2016 and 2015, respectively. The Postretirement Plans' assets had an actual gain of 5.39% for the year ended December 31, 2016 and an actual loss of 0.9% for the year ended December 31, 2015. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2016, AEP had cumulative losses of approximately $39 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses may result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2016 under this method was 4.05% for the Qualified Plan, 3.85% for the Nonqualified Plans and 4.1% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 6%, discount rates of 4.05% and 3.85% and various other assumptions, management estimates that the pension costs for the Pension Plans will approximate $96 million, $67 million and $59 million in 2017, 2018 and 2019, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 6.75%, a discount rate of 4.1% and various other assumptions, management estimates Postretirement Plan credits will approximate $66 million, $72 million and $76 million in 2017, 2018 and 2019, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of AEP's Pension Plans' assets remain unchanged at $4.8 billion as of December 31, 2016 and December 31, 2015 primarily due to investment returns and company contributions offsetting benefit payments from AEP System companies. During 2016, the Qualified Plan paid $340 million and the Nonqualified Plans paid $7 million in benefits to plan participants. The value of AEP's Postretirement Plans' assets decreased to $1.5 billion as of December 31, 2016 from $1.6 billion as of December 31, 2015 primarily due to benefit payments in excess of investment returns and contributions from AEP System companies and the participants. The Postretirement Plans paid $130 million in benefits to plan participants during 2016.

Nature of Estimates Required

AEP sponsors pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under "Compensation" and "Plan Accounting" accounting guidance. The measurement of pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2016 Benefit Obligations				
Discount Rate	$ (262.9)	$ 289.1	$ (74.7)	$ 82.2
Compensation Increase Rate	20.5	(18.7)	NA	NA
Cash Balance Crediting Rate	71.0	(64.8)	NA	NA
Health Care Cost Trend Rate	NA	NA	27.8	(25.9)
Effect on 2016 Periodic Cost				
Discount Rate	(13.2)	14.3	(3.1)	3.3
Compensation Increase Rate	5.0	(4.5)	NA	NA
Cash Balance Crediting Rate	13.9	(12.9)	NA	NA
Health Care Cost Trend Rate	NA	NA	3.3	(3.0)
Expected Return on Plan Assets	(23.4)	23.4	(7.7)	7.7

NA Not applicable.

ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2016

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

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

Pronouncements Effective in the Future

The FASB issued ASU 2014-09 "Revenue from Contracts with Customers" clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts. The FASB deferred implementation of ASU 2014-09 under the terms in ASU 2015-14, "Revenue from Contracts with Customers (Topic: 606): Deferral of the Effective Date." The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. Management continues to analyze the impact of the new revenue standard and related ASUs. During 2016, initial 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. Management also continues to monitor unresolved industry implementation issues, including items related to collectability and alternative revenue programs, and will analyze the related impacts to revenue recognition. Management plans to adopt ASU 2014-09 effective January 1, 2018.

The FASB issued ASU 2015-11 "Simplifying the Measurement of Inventory" to simplify the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, inventory should be at the lower of cost and net realizable value. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2016 with early adoption permitted. Management 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 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" enhancing the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheet or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets. The new accounting guidance is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted. The amendments will be applied by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-01 effective January 1, 2018.

The FASB issued ASU 2016-02 "Accounting for Leases" increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet 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, initial 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. Lease system options are currently being 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.

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 renewables and PPAs, 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 2016-09 "Compensation – Stock Compensation" simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income. The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management adopted ASU 2016-09 effective January 1, 2017. There was no impact on results of operations, financial position or cash flows at adoption.

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.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including hedge accounting, consolidations and pension and postretirement benefits. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

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

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates. In addition, the Generation & Marketing segment is also exposed to certain market risks as a major power producer and through transactions in wholesale electricity and 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 Vice Chairman, 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 Vice Chairman, Chief Financial Officer, and Chief Risk Officer in addition to Energy Supply's President and Vice President. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2015:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2016

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets as of December 31, 2015	$ 8.6	$ 14.4	$ 143.2	$ 166.2
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(12.9)	4.8	(16.3)	(24.4)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	30.5	30.5
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	6.8	6.8
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	9.5	(137.4)	—	(127.9)
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2016	$ 5.2	$ (118.2)	$ 164.2	51.2
Commodity Cash Flow Hedge Contracts				(35.5)
Fair Value Hedge Contracts				(1.4)
Collateral Deposits				(0.3)
Total MTM Derivative Contract Net Assets as of December 31, 2016				$ 14.0

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

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

AEP has risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of December 31, 2016, credit exposure net of collateral to sub investment grade counterparties was approximately 7.1%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2016, the following table approximates AEP's counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 686.7	$ 2.6	$ 684.1	3	$ 356.1
Split Rating	16.4	—	16.4	1	16.0
Noninvestment Grade	0.1	—	0.1	1	0.1
No External Ratings:					
Internal Investment Grade	105.7	—	105.7	2	55.9
Internal Noninvestment Grade	73.1	11.3	61.8	3	39.2
Total as of December 31, 2016	$ 882.0	$ 13.9	$ 868.1		

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2016, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

Management calculates the VaR for both a trading and non-trading portfolio. The trading portfolio consists primarily of contracts related to energy trading and marketing activities. The non-trading portfolio consists primarily of economic hedges of generation and retail supply activities. The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio

Twelve Months Ended December 31, 2016				Twelve Months Ended December 31, 2015			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.2	$ 1.1	$ 0.2	$ 0.1	$ 0.2	$ 0.9	$ 0.2	$ 0.1

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2016				Twelve Months Ended December 31, 2015			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 5.6	$ 8.4	$ 1.5	$ 0.4	$ 1.1	$ 2.4	$ 0.9	$ 0.4

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

As the VaR calculation captures recent price movements, management also performs regular stress testing of the trading portfolio to understand AEP's exposure to extreme price movements. A historical-based method is employed whereby the current trading portfolio is subjected to actual, observed price movements from the last several years in order to ascertain which historical price movements translated into the largest potential MTM loss. Management then researches the underlying positions, price movements and market events that created the most significant exposure and reports the findings to the Risk Executive Committee, Regulated Risk Committee, or Competitive Risk Committee as appropriate.

Interest Rate Risk

Management utilizes an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2016 and 2015, the estimated EaR on AEP's debt portfolio for the following twelve months was $29 million and $25 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February-- 27, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of the Company and our report dated February 27, 2017 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15 (f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP’s internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP’s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO 2013) in Internal Control – Integrated Framework. Based on management’s assessment, AEP’s internal control over financial reporting was effective as of December 31, 2016.

AEP’s independent registered public accounting firm has issued an attestation report on AEP’s internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2016, 2015 and 2014
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2016	2015	2014
REVENUES			
Vertically Integrated Utilities	$ 9,012.4	$ 9,069.9	$ 9,396.8
Transmission and Distribution Utilities	4,328.3	4,392.0	4,552.6
Generation & Marketing	2,858.7	2,866.7	2,384.3
Other Revenues	180.7	124.6	44.9
TOTAL REVENUES	16,380.1	16,453.2	16,378.6
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	2,908.9	3,348.1	4,271.8
Purchased Electricity for Resale	2,821.4	2,760.1	2,085.9
Other Operation	2,956.9	2,703.9	2,766.6
Maintenance	1,237.7	1,325.3	1,328.0
Asset Impairments and Other Related Charges	2,267.8	—	—
Depreciation and Amortization	1,962.3	2,009.7	1,897.6
Taxes Other Than Income Taxes	1,018.0	972.6	901.3
TOTAL EXPENSES	15,173.0	13,119.7	13,251.2
OPERATING INCOME	1,207.1	3,333.5	3,127.4
Other Income (Expense):			
Interest and Investment Income	16.3	7.9	7.4
Carrying Costs Income	16.2	23.5	33.2
Allowance for Equity Funds Used During Construction	113.2	131.9	102.9
Interest Expense	(877.2)	(873.9)	(868.0)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (CREDIT) AND EQUITY EARNINGS	475.6	2,622.9	2,402.9
Income Tax Expense (Credit)	(73.7)	919.6	902.6
Equity Earnings of Unconsolidated Subsidiaries	71.2	65.3	90.2
INCOME FROM CONTINUING OPERATIONS	620.5	1,768.6	1,590.5
INCOME (LOSS) FROM DISCONTINUED OPERATIONS, NET OF TAX	(2.5)	283.7	47.5
NET INCOME	618.0	2,052.3	1,638.0
Net Income Attributable to Noncontrolling Interests	7.1	5.2	4.2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 610.9	$ 2,047.1	$ 1,633.8
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	491,495,458	490,340,522	488,592,997
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 1.25	$ 3.59	$ 3.24
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	(0.01)	0.58	0.10
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.24	$ 4.17	$ 3.34
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	491,662,007	490,574,568	488,899,840
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 1.25	$ 3.59	$ 3.24
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	(0.01)	0.58	0.10
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.24	$ 4.17	$ 3.34

See Notes to Financial Statements of Registrants beginning on page 69.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2016, 2015 and 2014
(in millions)

	Years Ended December 31, 2016	2015	2014
Net Income	$ 618.0	$ 2,052.3	$ 1,638.0
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(8.8), $(2.6) and $2.9 in 2016, 2015 and 2014, Respectively	(16.4)	(4.9)	5.3
Securities Available for Sale, Net of Tax of $0.7, $(0.3) and $0.4 in 2016, 2015 and 2014, Respectively	1.3	(0.6)	0.9
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0.3, $0.6 and $2.6 in 2016, 2015 and 2014, Respectively	0.6	1.2	4.8
Pension and OPEB Funded Status, Net of Tax of $(7.9), $(13.9) and $0.6 in 2016, 2015 and 2014, Respectively	(14.7)	(25.7)	1.1
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(29.2)	(30.0)	12.1
TOTAL COMPREHENSIVE INCOME	588.8	2,022.3	1,650.1
Total Comprehensive Income Attributable to Noncontrolling Interests	7.1	5.2	4.2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 581.7	$ 2,017.1	$ 1,645.9

See Notes to Financial Statements of Registrants beginning on page 69.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2016, 2015 and 2014
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2013	508.1	$ 3,302.7	$ 6,131.2	$ 6,766.1	$ (115.2)	$ 0.8	$ 16,085.6
Issuance of Common Stock	1.6	10.6	63.0				73.6
Common Stock Dividends				(993.3) (a)		(4.3)	(997.6)
Other Changes in Equity			9.2			3.6	12.8
Net Income				1,633.8		4.2	1,638.0
Other Comprehensive Income					12.1		12.1
TOTAL EQUITY – DECEMBER 31, 2014	509.7	3,313.3	6,203.4	7,406.6	(103.1)	4.3	16,824.5
Issuance of Common Stock	1.7	10.7	70.9				81.6
Common Stock Dividends				(1,055.4) (a)		(3.6)	(1,059.0)
Other Changes in Equity			22.2			7.3	29.5
Net Income				2,047.1		5.2	2,052.3
Other Comprehensive Loss					(30.0)		(30.0)
Pension and OPEB Adjustment Related to Mitchell Plant					6.0		6.0
TOTAL EQUITY – DECEMBER 31, 2015	511.4	3,324.0	6,296.5	8,398.3	(127.1)	13.2	17,904.9
Issuance of Common Stock	0.6	4.3	29.9				34.2
Common Stock Dividends				(1,116.8) (a)		(4.2)	(1,121.0)
Other Changes in Equity			6.2			7.0	13.2
Net Income				610.9		7.1	618.0
Other Comprehensive Loss					(29.2)		(29.2)
TOTAL EQUITY – DECEMBER 31, 2016	512.0	$ 3,328.3	$ 6,332.6	$ 7,892.4	$ (156.3)	$ 23.1	$ 17,420.1

(a) Cash dividends declared per AEP common share were $2.27, $2.15 and $2.03 for the years ended December 31, 2016, 2015 and 2014, respectively.

See Notes to Financial Statements of Registrants beginning on page 69.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2016 and 2015
(in millions)

	December 31, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 210.5	$ 176.4
Other Temporary Investments (December 31, 2016 and 2015 Amounts Include $322.5 and $376.6, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, EIS and Sabine)	331.7	386.8
Accounts Receivable:		
Customers	705.1	615.9
Accrued Unbilled Revenues	158.7	31.2
Pledged Accounts Receivable – AEP Credit	972.7	940.3
Miscellaneous	118.1	82.1
Allowance for Uncollectible Accounts	(37.9)	(29.0)
Total Accounts Receivable	1,916.7	1,640.5
Fuel	423.8	600.8
Materials and Supplies	543.5	738.6
Risk Management Assets	94.5	134.4
Regulatory Asset for Under-Recovered Fuel Costs	156.6	115.2
Margin Deposits	79.9	107.3
Assets Held for Sale	1,951.2	—
Prepayments and Other Current Assets	325.5	172.4
TOTAL CURRENT ASSETS	6,033.9	4,072.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	19,848.9	25,559.8
Transmission	16,658.7	14,247.9
Distribution	18,900.8	18,046.9
Other Property, Plant and Equipment (December 31, 2016 and 2015 Amounts Include Coal Mining and Nuclear Fuel, December 31, 2015 Amount Includes 2016 Plant Retirements)	3,444.3	3,722.9
Construction Work in Progress	3,183.9	3,903.9
Total Property, Plant and Equipment	62,036.6	65,481.4
Accumulated Depreciation and Amortization	16,397.3	19,348.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	45,639.3	46,133.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,625.5	5,140.3
Securitized Assets	1,486.1	1,749.9
Spent Nuclear Fuel and Decommissioning Trusts	2,256.2	2,106.4
Goodwill	52.5	52.5
Long-term Risk Management Assets	289.1	321.8
Deferred Charges and Other Noncurrent Assets	2,085.1	2,106.6
TOTAL OTHER NONCURRENT ASSETS	11,794.5	11,477.5
TOTAL ASSETS	$ 63,467.7	$ 61,683.1

See Notes to Financial Statements of Registrants beginning on page 69.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2016 and 2015
(dollars in millions)

	December 31, 2016	December 31, 2015
CURRENT LIABILITIES		
Accounts Payable	$ 1,688.5	$ 1,418.0
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	673.0	675.0
Other Short-term Debt	1,040.0	125.0
Total Short-term Debt	1,713.0	800.0
Long-term Debt Due Within One Year (December 31, 2016 and 2015 Amounts Include $427.5 and $410.4, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	2,878.0	1,831.8
Risk Management Liabilities	53.4	87.1
Customer Deposits	343.2	346.6
Accrued Taxes	1,048.0	979.1
Accrued Interest	227.2	226.9
Regulatory Liability for Over-Recovered Fuel Costs	8.0	113.9
Liabilities Held for Sale	235.9	—
Other Current Liabilities	1,302.8	1,305.1
TOTAL CURRENT LIABILITIES	9,498.0	7,108.5
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2016 and 2015 Amounts Include $1,737.5 and $1,971.4, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	17,378.4	17,740.9
Long-term Risk Management Liabilities	316.2	179.1
Deferred Income Taxes	11,884.4	11,733.2
Regulatory Liabilities and Deferred Investment Tax Credits	3,751.3	3,736.1
Asset Retirement Obligations	1,830.6	1,806.5
Employee Benefits and Pension Obligations	614.1	583.3
Deferred Credits and Other Noncurrent Liabilities	774.6	890.6
TOTAL NONCURRENT LIABILITIES	36,549.6	36,669.7
TOTAL LIABILITIES	46,047.6	43,778.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2016	2015
Shares Authorized	600,000,000	600,000,000
Shares Issued	512,048,520	511,389,173

	December 31, 2016	December 31, 2015
(20,336,592 Shares were Held in Treasury as of December 31, 2016 and 2015)	3,328.3	3,324.0
Paid-in Capital	6,332.6	6,296.5
Retained Earnings	7,892.4	8,398.3
Accumulated Other Comprehensive Income (Loss)	(156.3)	(127.1)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	17,397.0	17,891.7
Noncontrolling Interests	23.1	13.2
TOTAL EQUITY	17,420.1	17,904.9
TOTAL LIABILITIES AND EQUITY	$ 63,467.7	$ 61,683.1

See Notes to Financial Statements of Registrants beginning on page 69.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2016, 2015 and 2014
(in millions)

	Years Ended December 31,		
	2016	2015	2014
OPERATING ACTIVITIES			
Net Income	$ 618.0	$ 2,052.3	$ 1,638.0
Income (Loss) from Discontinued Operations	(2.5)	283.7	47.5
Income from Continuing Operations	620.5	1,768.6	1,590.5
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities:			
Depreciation and Amortization	1,962.3	2,009.7	1,897.6
Deferred Income Taxes	(50.0)	808.2	868.8
Asset Impairments and Other Related Charges	2,267.8	—	—
Carrying Costs Income	(16.2)	(23.5)	(33.2)
Allowance for Equity Funds Used During Construction	(113.2)	(131.9)	(102.9)
Mark-to-Market of Risk Management Contracts	150.8	52.5	(53.1)
Amortization of Nuclear Fuel	128.6	145.0	144.2
Pension and Postemployment Benefit Reserves	21.6	33.2	77.2
Pension Contributions to Qualified Plan Trust	(84.8)	(91.8)	(70.3)
Property Taxes	(19.0)	(52.4)	(41.8)
Deferred Fuel Over/Under-Recovery, Net	(65.5)	137.8	(35.5)
Recovery (Deferral) of Ohio Capacity Costs, Net	88.1	65.5	(113.5)
Provision for Refund – Global Settlement	120.3	—	—
Disposition of Tanners Creek Plant Site	(93.5)	—	—
Change in Other Noncurrent Assets	(438.4)	(105.7)	35.6
Change in Other Noncurrent Liabilities	15.4	(89.0)	256.1
Changes in Certain Components of Continuing Working Capital:			
Accounts Receivable, Net	(226.6)	200.2	(60.3)
Fuel, Materials and Supplies	60.2	(38.6)	100.8
Accounts Payable	164.9	16.5	(74.9)
Accrued Taxes, Net	42.8	120.2	0.4
Other Current Assets	14.2	(26.7)	(20.6)
Other Current Liabilities	(28.5)	(49.1)	237.3
Net Cash Flows from Continuing Operating Activities	4,521.8	4,748.7	4,602.4
INVESTING ACTIVITIES			
Construction Expenditures	(4,781.1)	(4,508.0)	(4,130.0)
Change in Other Temporary Investments, Net	57.4	9.6	(31.1)
Purchases of Investment Securities	(3,002.3)	(2,282.7)	(1,088.0)
Sales of Investment Securities	2,957.7	2,218.4	1,031.8
Acquisitions of Nuclear Fuel	(128.5)	(92.0)	(116.2)
Acquisitions of Assets/Businesses	(107.9)	(5.3)	(64.8)
Other Investing Activities	15.6	96.0	(7.6)
Net Cash Flows Used for Continuing Investing Activities	(4,989.1)	(4,564.0)	(4,405.9)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	34.2	81.6	73.6
Issuance of Long-term Debt	2,594.9	3,436.6	2,067.0
Change in Short-term Debt, Net	913.0	(546.0)	589.0
Retirement of Long-term Debt	(1,794.9)	(2,397.9)	(1,777.4)
Make Whole Premium on Extinguishment of Long-term Debt	—	(92.7)	—
Principal Payments for Capital Lease Obligations	(106.6)	(99.0)	(111.2)
Dividends Paid on Common Stock	(1,121.0)	(1,059.0)	(997.6)
Other Financing Activities	(15.7)	14.7	5.7
Net Cash Flows from (Used for) Continuing Financing Activities	503.9	(661.7)	(150.9)
Net Cash Flows from (Used for) Discontinued Operating Activities	(2.5)	69.8	11.1
Net Cash Flows from (Used for) Discontinued Investing Activities	—	548.8	(0.1)
Net Cash Flows Used for Discontinued Financing Activities	—	(127.7)	(11.6)
Net Increase in Cash and Cash Equivalents	34.1	13.9	45.0
Cash and Cash Equivalents at Beginning of Period	176.4	162.5	117.5
Cash and Cash Equivalents at End of Period	$ 210.5	$ 176.4	$ 162.5

See Notes to Financial Statements of Registrants beginning on page 69.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

The notes to financial statements are a combined presentation for the Registrants. The following list indicates Registrants to which the notes apply. Specific disclosures within each note apply to all Registrants unless indicated otherwise.

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

ORGANIZATION

The Registrants engage in the generation, transmission and distribution of electric power. The Registrant Subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. Most of these companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

AEP provides competitive electric and gas supply for residential, commercial and industrial customers in Ohio, Illinois and other deregulated electricity markets and also provides energy management solutions throughout the United States, including energy efficiency services through its independent retail electric supplier.

The Registrants also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, operations include barging operations and competitive wind and solar farms. I&M provides barging services to both affiliated and nonaffiliated companies. SWEPCo, through consolidated and nonconsolidated affiliates, conducts lignite mining operations to fuel certain of its generation facilities.

Disposition of AEP River Operations

In October 2015, AEP signed an agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated third party. The sale closed in November 2015. The results of operations of AEPRO have been classified as Discontinued Operations on the statements of income for the current period and prior periods presented. The transaction was accounted for in accordance with the accounting guidance for "Presentation of Financial Statements and Property, Plant and Equipment." Material disclosures within the notes to the financial statements exclude amounts related to Discontinued Operations for all periods presented. See "AEPRO (Corporate and Other)" section of Note 7 for additional information.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP's public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in the eleven state operating territories in which they operate. The FERC also regulates the Registrants' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. The Registrants' wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that the Registrants have "market power" in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrants' retail public utility subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. For generation in Ohio, customers who have not switched to a CRES provider for generation pay market-based auction rates. In addition, all OPCo distribution customers pay for certain deferred generation-related costs through non-bypassable charges. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing is conducted by Texas Retail Electric Providers (REPs). AEP has no active REPs in ERCOT. AEP's nonregulated subsidiaries enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT.

The FERC also regulates the Registrants' wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Retail transmission rates are based on formula rates included in the PJM OATT that are cost-based and are unbundled in Ohio for OPCo, in Virginia for APCo and in Michigan for I&M. AEP Texas' retail transmission rates in Texas are unbundled but the retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for AEP's seven wholly-owned transmission subsidiaries within the AEP Transmission Holdco segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

In West Virginia, APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a combined cost-of-service basis.

In addition, the FERC regulates the SIA, the Operating Agreement, the Transmission Agreement and the Transmission Coordination Agreement, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. In 2013, the FERC issued orders approving the creation of a PCA and a Power Supply Agreement (PSA), effective January 2014. The PCA is among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Effective May 2015, the PCA was revised and approved by the FERC to include WPCo. Also effective January 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The PSA term ended in May 2015. Effective June 2014, the FERC approved the cancellation of the System Transmission Integration Agreement.

Principles of Consolidation

AEP's consolidated financial statements include its wholly-owned and majority-owned subsidiaries and VIEs of which AEP is the primary beneficiary. The consolidated financial statements for APCo include the Registrant Subsidiary, its wholly-owned subsidiaries and Appalachian Consumer Rate Relief Funding (a substantially-controlled VIE). The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (substantially-controlled VIEs). The consolidated financial statements for OPCo include the Registrant Subsidiary and Ohio Phase-in-Recovery Funding (a substantially-controlled VIE). The consolidated financial statements for SWEPCo include the Registrant Subsidiary, its wholly-owned subsidiary and Sabine (a substantially-controlled VIE). Intercompany items are eliminated in consolidation. The equity method of accounting is used for equity investments where the Registrants exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. Equity method investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value. AEP, I&M, PSO and SWEPCo have ownership interests in generating units that are jointly-owned. The proportionate share of the operating costs associated with such facilities is included in the income statements and the assets and liabilities are reflected on the balance sheets. See Note 17 - Variable Interest Entities and Note 18 - Property, Plant and Equipment.

Accounting for the Effects of Cost-Based Regulation

The Registrants' financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Other Temporary Investments (Applies to AEP)

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and securities available for sale, including marketable securities that management intends to hold for less than one year and investments by its protected cell of EIS.

Management classifies investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. AEP does not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, management considers, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" in Note 11.

Restricted Cash for Securitized Funding (Applies to APCo and OPCo)

Restricted Cash for Securitized Funding includes funds held by trustees primarily for the payment of securitization bonds.

Inventory

Fossil fuel inventories are carried at average cost with the exception of AGR and AEP's non-regulated ownership share of Oklaunion Plant, which is carried at the lower of average cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, the Registrants accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for the interest in the billed and unbilled receivables AEP Credit acquires from affiliated utility subsidiaries. See "Sale of Receivables – AEP Credit" section of Note 14 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For AEP Texas, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers (Applies to Registrant Subsidiaries)

The Registrant Subsidiaries do not have any significant customers that comprise 10% or more of their operating revenues for the year ended December 31, 2016.

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuing basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying Registrant Subsidiary financial statements.

Emission Allowances

In regulated jurisdictions, the Registrants record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. For AEP's competitive generation business, management records allowances at the lower of cost or market. The Registrants follow the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies on the balance sheets. Allowances with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost on the statements of income. The net margin on sales of emission allowances is included in Vertically Integrated Utilities Revenue on AEP's statements of income and in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates for affiliated transactions on Registrant Subsidiaries' statements of income because of its integral nature to the production process of energy and the Registrants' revenue optimization strategy for their operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment

Regulated

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs accrued are typically recorded as regulatory liabilities when removal costs accrued exceed actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Nonregulated operations generally follow the policies of rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations are stated at original cost (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction and Interest Capitalization

For regulated operations, AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. The Registrants record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's 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 Vice Chairman, 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 Vice Chairman, Chief Financial Officer and Chief Risk Officer in addition to Energy Supply's President and Vice President.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits and nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalent funds. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are primarily real estate, infrastructure and private equity investments that are valued using methods requiring judgment including appraisals. The fair value of real estate and infrastructure investments is measured using market capitalization rates, recent sales of comparable investments and independent third-party appraisals. The fair value of private equity investments is measured using cost and purchase multiples, operating results, discounted future cash flows and market based comparable data. Depending on the specific situation, one or multiple approaches are used to determine the valuation of a real estate, infrastructure or private equity investment.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrants' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable.

Changes in fuel costs, including purchased power in Kentucky for KPCo, Indiana and Michigan for I&M, in Ohio (through the ESP related to standard service offer load served through auctions) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO, in Virginia and West Virginia for APCo and in West Virginia for WPCo are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (from 2009 through 2011) for OPCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales margins. In West Virginia for APCo and WPCo, all of the non-merchant margins from off-system sales are given to customers through the FAC. A portion of margins from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are tested for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the regulatory asset is written off as a charge against income.

Electricity Supply and Delivery Activities

The Registrants recognize revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrants recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue. Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. The annual rate filing is compared to actual costs with an over- or under-recovery being trued-up with interest and refunded or recovered in a future year's rates.

Most of the power produced at the generation plants is sold to PJM or SPP. The Registrants also purchase power from PJM and SPP to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM or SPP, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. With the exception of certain dedicated load bilateral power supply contracts, the transactions of AEP's nonregulated subsidiaries are reported as gross purchases or sales.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, the Registrants record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

The Registrants engage in power, capacity and, to a lesser extent, natural gas marketing as major power producers and participants in electricity and natural gas markets. The Registrants also engage in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

The Registrants recognize revenues and expenses from marketing and risk management transactions that are not derivatives upon delivery of the commodity. The Registrants use MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The Registrants include realized gains and losses on marketing and risk management transactions in revenues or expense based on the transaction's facts and circumstances. In certain jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event the Registrants designate a cash flow hedge, the effective portion of the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, the Registrants subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. In regulated jurisdictions, the ineffective portion is deferred as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 10.

Barging Activities (Applies to AEP)

AEP River Operations' revenue, which is presented in Discontinued Operations, was recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized was determined by applying a percentage to the contractual charges for such services. The percentage was determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end was determined by AEP's computerized barge tracking system. See the "AEPRO (Corporate and Other)" section of Note 7.

SPP Integrated Power Market (Applies to AEP, PSO and SWEPCo)

In March 2014, SPP changed from an energy imbalance service market to a fully integrated power market. In the past, PSO and SWEPCo would satisfy their load requirements with their own generation resources or through the Operating Agreement. In the new integrated power market, PSO and SWEPCo operate as standalone entities by offering their respective generation into the SPP power market, which then economically dispatches the resources. This change further enables retail customers to obtain power through either internal generation or power purchases from the SPP market. The new integrated power market now operates in a similar manner as the PJM power market for the AEP East Companies. The change in the SPP integrated power market did not have a significant effect on the results of operations or cash flows.

Levelization of Nuclear Refueling Outage Costs (Applies to AEP and I&M)

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

The Registrants expense maintenance costs as incurred. If it becomes probable that the Registrants will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulated jurisdictions, the Registrants defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

The Registrants use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits (ITC) were historically accounted for under the flow-through method, except where regulatory commissions reflected ITC in the rate-making process. In the third quarter of 2016, AEP and subsidiaries changed accounting for the recognition of ITC and elected to apply the preferred deferral methodology. Retrospective application is not necessary for reporting periods prior to 2016 as the financial impact to AEP and subsidiaries was immaterial.

Deferred ITC is amortized to income tax expense over the life of the asset. Amortization of deferred ITC begins when the asset is placed into service, except where regulatory commissions reflect ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

The Registrants account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." The Registrants classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes

As agents for some state and local governments, the Registrants collect from customers certain excise taxes levied by those state or local governments on customers. The Registrants do not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense on the statements of income.

Goodwill and Intangible Assets (Applies to AEP)

When AEP acquires businesses, management records the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, goodwill is recorded. Goodwill and intangible assets with indefinite lives are not amortized. Management tests acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. Management tests goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods. AEP amortizes intangible assets with finite lives over their respective estimated lives to their estimated residual values. AEP also reviews the lives of the amortizable intangibles with finite lives on an annual basis.

Pension and OPEB Plans

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Registrant Subsidiaries are allocated a proportionate share of benefit costs and account for their participation in these plans as multiple-employer plans. See Note 8 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	25%
Fixed Income	59%
Other Investments	15%
Cash and Cash Equivalents	1%

OPEB Plans Assets	Target
Equity	65%
Fixed Income	33%
Cash and Cash Equivalents	2%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts, which are publicly traded real estate securities.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds (Applies to AEP and I&M)

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

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

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Stock-Based Compensation Plans

As of December 31, 2016, AEP had performance units and restricted stock units outstanding under the American Electric Power System Long-Term Incentive Plan (LTIP). Upon vesting, performance units are paid in cash and restricted stock units are settled in AEP common shares, except for restricted stock units granted after January 1, 2013 and vesting to executive officers, which are paid in cash. The impact of AEP's stock-based compensation plans are insignificant to the financial statements of the Registrant Subsidiaries.

AEP maintains a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes AEP career shares maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. AEP career shares are derived from vested performance units granted to employees under the LTIP. AEP career shares are equal in value to shares of AEP common stock and become payable to executives in cash after their service ends. AEP career shares accrue additional dividend shares in an amount equal to dividends paid on AEP common shares at the closing market price on the dividend payments date.

AEP compensates their non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

Management measures and recognizes compensation expense for all share-based payment awards to employees and directors based on estimated fair values. For share-based payment awards with service only vesting conditions, management recognizes compensation expense on a straight-line basis. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2016, 2015 and 2014 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2016, 2015 and 2014, compensation expense is included in Net Income for the performance units, career shares, restricted stock units and the non-employee director's stock units. See Note 15 for additional discussion.

Earnings Per Share (EPS) (Applies to AEP)

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

The following table presents AEP's basic and diluted EPS calculations included on the statements of income:

	Years Ended December 31,					
	2016		2015		2014	
	(in millions, except per share data)					
		$/share		$/share		$/share
Income from Continuing Operations	$ 620.5		$1,768.6		$1,590.5	
Less: Net Income Attributable to Noncontrolling Interests	7.1		5.2		4.2	
Earnings Attributable to AEP Common Shareholders from Continuing Operations	$ 613.4		$1,763.4		$1,586.3	
Weighted Average Number of Basic Shares Outstanding	491.5	$ 1.25	490.3	$ 3.59	488.6	$ 3.24
Weighted Average Dilutive Effect of Restricted Stock Units	0.2	—	0.3	—	0.3	—
Weighted Average Number of Diluted Shares Outstanding	491.7	$ 1.25	490.6	$ 3.59	488.9	$ 3.24

There were no antidilutive shares outstanding as of December 31, 2016, 2015 and 2014.

Supplementary Related Party Information (Applies to AEP)

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2016, AEP's ownership and investment in OVEC were 43.47% and $4 million, respectively.

OVEC's owners are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2016, OVEC's outstanding indebtedness is approximately $1.5 billion. AEP is responsible for their 43.47% share of OVEC's outstanding debt. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6.

The following details related party transactions for the years ended December 31, 2016, 2015 and 2014:

Related Party Transactions	Years Ended December 31, 2016	2015	2014
		(in millions)	
AEP Revenues – Other Revenues:			
OVEC – Barging and Other Transportation Services (a)	$ 0.2	$ 0.1	$ 24.0
AEP Expenses – Purchased Electricity for Resale:			
OVEC	243.7	241.7	268.5

(a) AEP did not ship coal to OVEC in 2016 and 2015.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2016, 2015 and 2014:

2016

Depreciation and Amortization	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Depreciation and Amortization of Property, Plant and Equipment	$ 1,688.5	$ 387.6	$ 183.9	$ 202.3	$ 122.6	$ 196.6
Amortization of Certain Securitized Assets	254.6	—	—	44.3	—	—
Amortization of Regulatory Assets and Liabilities	19.2	0.9	7.8	(8.0)	7.6	(0.1)
Total Depreciation and Amortization	$ 1,962.3	$ 388.5	$ 191.7	$ 238.6	$ 130.2	$ 196.5

2015

Depreciation and Amortization	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Depreciation and Amortization of Property, Plant and Equipment	$ 1,674.3	$ 385.6	$ 193.5	$ 184.4	$ 108.6	$ 190.7
Amortization of Certain Securitized Assets	318.9	—	—	43.3	—	—
Amortization of Regulatory Assets and Liabilities	16.5	3.2	4.9	(10.2)	8.9	1.3
Total Depreciation and Amortization	$ 2,009.7	$ 388.8	$ 198.4	$ 217.5	$ 117.5	$ 192.0

2014

Depreciation and Amortization	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Depreciation and Amortization of Property, Plant and Equipment	$ 1,573.7	$ 383.3	$ 199.3	$ 188.3	$ 99.7	$ 183.2
Amortization of Certain Securitized Assets	310.4	—	—	43.5	—	—
Amortization of Regulatory Assets and Liabilities	13.5	17.6	0.9	(18.1)	1.3	1.9
Total Depreciation and Amortization	$ 1,897.6	$ 400.9	$ 200.2	$ 213.7	$ 101.0	$ 185.1

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Years Ended December 31, 2016	2015	2014
		(in millions)	
Cash Paid for:			
Interest, Net of Capitalized Amounts	$ 848.5	$ 857.2	$ 838.5
Income Taxes	29.5	120.2	117.3
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	86.1	150.2	135.1
Construction Expenditures Included in Current Liabilities as of December 31,	858.0	741.4	559.3
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	—	51.6	—
Construction Expenditures Included in Noncurrent Assets as of December 31,	—	10.5	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	2.1	37.9	44.5
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	0.7	2.2	3.4

2. NEW ACCOUNTING PRONOUNCEMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrants' business. The following final pronouncements will impact the financial statements.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 clarifying the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract, 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, initial 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. Management also continues to monitor unresolved industry implementation issues, including items related to collectability and alternative revenue programs, and will analyze the related impacts to revenue recognition. Management plans to adopt ASU 2014-09 effective January 1, 2018.

ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11)

In July 2015, the FASB issued ASU 2015-11 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.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

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

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

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet 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, initial 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. Lease system options are currently being 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.

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 renewables and PPAs, 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.

ASU 2016-09 "Compensation – Stock Compensation" (ASU 2016-09)

In March 2016, the FASB issued ASU 2016-09 simplifying the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statements of cash flows. Under the new standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit on the statements of income. Under current GAAP, excess tax benefits are recognized in additional paid-in capital while tax deficiencies are recognized either as an offset to accumulated excess tax benefits, if any, or on the statements of income.

The new accounting guidance is effective for annual periods beginning after December 15, 2016. Early adoption is permitted in any interim or annual period. Certain provisions require retrospective/modified retrospective transition while others are to be applied prospectively. Management adopted ASU 2016-09 effective January 1, 2017. There was no impact on results of operations, financial position or cash flows at adoption.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 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.

ASU 2016-18 "Restricted Cash" (ASU 2016-18)

In November 2016, the FASB issued ASU 2016-18 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.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants unless indicated otherwise.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2016, 2015 and 2014. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 for additional details.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2015	$ (5.2)	$ (17.2)	$ 7.1	$ 139.9	$ (251.7)	$ (127.1)
Change in Fair Value Recognized in AOCI	(14.6)	—	1.3	—	(14.7)	(28.0)
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues	(21.4)	—	—	—	—	(21.4)
Purchased Electricity for Resale	16.4	—	—	—	—	16.4
Interest Expense	—	2.4	—	—	—	2.4
Amortization of Prior Service Cost (Credit)	—	—	—	(19.4)	—	(19.4)
Amortization of Actuarial (Gains)/Losses	—	—	—	20.3	—	20.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	(5.0)	2.4	—	0.9	—	(1.7)
Income Tax (Expense) Credit	(1.7)	0.9	—	0.3	—	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(3.3)	1.5	—	0.6	—	(1.2)
Net Current Period Other Comprehensive Income (Loss)	(17.9)	1.5	1.3	0.6	(14.7)	(29.2)
Balance in AOCI as of December 31, 2016	$ (23.1)	$ (15.7)	$ 8.4	$ 140.5	$ (266.4)	$ (156.3)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2014	$ 1.6	$ (19.1)	$ 7.7	$ 138.7	$ (232.0)	$ (103.1)
Change in Fair Value Recognized in AOCI	5.6	—	(0.6)	—	(25.7)	(20.7)
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues	(48.1)	—	—	—	—	(48.1)
Purchased Electricity for Resale	29.1	—	—	—	—	29.1
Interest Expense	—	2.9	—	—	—	2.9
Amortization of Prior Service Cost (Credit)	—	—	—	(19.5)	—	(19.5)
Amortization of Actuarial (Gains)/Losses	—	—	—	21.3	—	21.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	(19.0)	2.9	—	1.8	—	(14.3)
Income Tax (Expense) Credit	(6.6)	1.0	—	0.6	—	(5.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(12.4)	1.9	—	1.2	—	(9.3)
Net Current Period Other Comprehensive Income (Loss)	(6.8)	1.9	(0.6)	1.2	(25.7)	(30.0)
Balance in AOCI as of Pension and OPEB Adjustment Related to Mitchell Plant	—	—	—	—	6.0	6.0
Balance in AOCI as of December 31, 2015	$ (5.2)	$ (17.2)	$ 7.1	$ 139.9	$ (251.7)	$ (127.1)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2014

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2013	$ 0.2	$ (23.0)	$ 6.8	$ 133.9	$ (233.1)	$ (115.2)
Change in Fair Value Recognized in AOCI	(9.8)	—	0.9	—	1.1	(7.8)
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues	59.1	—	—	—	—	59.1
Purchased Electricity for Resale	(39.1)	—	—	—	—	(39.1)
Regulatory Assets/(Liabilities), Net (a)	(2.8)	—	—	—	—	(2.8)
Interest Expense	—	6.1	—	—	—	6.1
Amortization of Prior Service Cost (Credit)	—	—	—	(20.6)	—	(20.6)
Amortization of Actuarial (Gains)/Losses	—	—	—	28.0	—	28.0
Reclassifications from AOCI, before Income Tax (Expense) Credit	17.2	6.1	—	7.4	—	30.7
Income Tax (Expense) Credit	6.0	2.2	—	2.6	—	10.8
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	11.2	3.9	—	4.8	—	19.9
Net Current Period Other Comprehensive Income	1.4	3.9	0.9	4.8	1.1	12.1
Balance in AOCI as of December 31, 2014	$ 1.6	$ (19.1)	$ 7.7	$ 138.7	$ (232.0)	$ (103.1)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2015	$ —	$ 3.6	$ 17.4	$ (23.8)	$ (2.8)
Change in Fair Value Recognized in AOCI	—	—	—	(3.5)	(3.5)
Amount of (Gain) Loss Reclassified from AOCI					
Interest Expense	—	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	—	(5.1)	—	(5.1)
Amortization of Actuarial (Gains)/Losses	—	—	3.0	—	3.0
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	(1.1)	(2.1)	—	(3.2)
Income Tax (Expense) Credit	—	(0.4)	(0.7)	—	(1.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	(0.7)	(1.4)	—	(2.1)
Net Current Period Other Comprehensive Loss	—	(0.7)	(1.4)	(3.5)	(5.6)
Balance in AOCI as of December 31, 2016	$ —	$ 2.9	$ 16.0	$ (27.3)	$ (8.4)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2014	$ —	$ 3.9	$ 19.2	$ (18.1)	$ 5.0
Change in Fair Value Recognized in AOCI	—	—	—	(5.7)	(5.7)
Amount of (Gain) Loss Reclassified from AOCI					
Interest Expense	—	(0.4)	—	—	(0.4)
Amortization of Prior Service Cost (Credit)	—	—	(5.1)	—	(5.1)
Amortization of Actuarial (Gains)/Losses	—	—	2.3	—	2.3
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	(0.4)	(2.8)	—	(3.2)
Income Tax (Expense) Credit	—	(0.1)	(1.0)	—	(1.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	(0.3)	(1.8)	—	(2.1)
Net Current Period Other Comprehensive Loss	—	(0.3)	(1.8)	(5.7)	(7.8)
Balance in AOCI as of December 31, 2015	$ —	$ 3.6	$ 17.4	$ (23.8)	$ (2.8)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2014

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2013	$ 0.1	$ 3.1	$ 20.5	$ (20.8)	$ 2.9
Change in Fair Value Recognized in AOCI	1.7	—	—	2.7	4.4
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale	(0.5)	—	—	—	(0.5)
Regulatory Assets/(Liabilities), Net (a)	(2.2)	—	—	—	(2.2)
Interest Expense	—	1.2	—	—	1.2
Amortization of Prior Service Cost (Credit)	—	—	(5.1)	—	(5.1)
Amortization of Actuarial (Gains)/Losses	—	—	3.1	—	3.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	(2.7)	1.2	(2.0)	—	(3.5)
Income Tax (Expense) Credit	(0.9)	0.4	(0.7)	—	(1.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(1.8)	0.8	(1.3)	—	(2.3)
Net Current Period Other Comprehensive Income (Loss)	(0.1)	0.8	(1.3)	2.7	2.1
Balance in AOCI as of December 31, 2014	$ —	$ 3.9	$ 19.2	$ (18.1)	$ 5.0

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2015	$ —	$ (13.3)	$ 5.1	$ (8.5)	$ (16.7)
Change in Fair Value Recognized in AOCI	—	—	—	(0.8)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI					
Interest Expense	—	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains)/Losses	—	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	2.0	—	—	2.0
Income Tax (Expense) Credit	—	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	—	1.3	—	(0.8)	0.5
Balance in AOCI as of December 31, 2016	$ —	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2014	$ —	$ (14.4)	$ 5.1	$ (5.0)	$ (14.3)
Change in Fair Value Recognized in AOCI	—	—	—	(3.5)	(3.5)
Amount of (Gain) Loss Reclassified from AOCI					
Interest Expense	—	1.7	—	—	1.7
Amortization of Prior Service Cost (Credit)	—	—	(0.9)	—	(0.9)
Amortization of Actuarial (Gains)/Losses	—	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	1.7	—	—	1.7
Income Tax (Expense) Credit	—	0.6	—	—	0.6
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	1.1	—	—	1.1
Net Current Period Other Comprehensive Income (Loss)	—	1.1	—	(3.5)	(2.4)
Balance in AOCI as of December 31, 2015	$ —	$ (13.3)	$ 5.1	$ (8.5)	$ (16.7)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2014

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2013	$ 0.1	$ (16.0)	$ 4.9	$ (4.5)	$ (15.5)
Change in Fair Value Recognized in AOCI	1.1	—	—	(0.5)	0.6
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale	(0.8)	—	—	—	(0.8)
Regulatory Assets/(Liabilities), Net (a)	(1.0)	—	—	—	(1.0)
Interest Expense	—	2.4	—	—	2.4
Amortization of Prior Service Cost (Credit)	—	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains)/Losses	—	—	1.1	—	1.1
Reclassifications from AOCI, before Income Tax (Expense) Credit	(1.8)	2.4	0.3	—	0.9
Income Tax (Expense) Credit	(0.6)	0.8	0.1	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(1.2)	1.6	0.2	—	0.6
Net Current Period Other Comprehensive Income (Loss)	(0.1)	1.6	0.2	(0.5)	1.2
Balance in AOCI as of December 31, 2014	$ —	$ (14.4)	$ 5.1	$ (5.0)	$ (14.3)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges		
	Commodity	Interest Rate	Total
		(in millions)	
Balance in AOCI as of December 31, 2015	$ —	$ 4.3	$ 4.3
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	—	(1.9)	(1.9)
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	(1.9)	(1.9)
Income Tax (Expense) Credit	—	(0.6)	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	(1.3)	(1.3)
Net Current Period Other Comprehensive Loss	—	(1.3)	(1.3)
Balance in AOCI as of December 31, 2016	$ —	$ 3.0	$ 3.0

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2014	$ —	$ 5.6	$ 58.4	$ (58.4)	$ 5.6
Change in Fair Value Recognized in AOCI	—	—	—	—	—
Amount of (Gain) Loss Reclassified from AOCI					
Interest Expense	—	(2.0)	—	—	(2.0)
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	(2.0)	—	—	(2.0)
Income Tax (Expense) Credit	—	(0.7)	—	—	(0.7)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	(1.3)	—	—	(1.3)
Net Current Period Other Comprehensive Loss	—	(1.3)	—	—	(1.3)
Balance in AOCI as of December 31, 2015	$ —	$ 4.3	$ 58.4	$ (58.4)	$ 4.3

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2014

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2013	$ 0.1	$ 7.0	$ 58.4	$ (58.4)	$ 7.1
Change in Fair Value Recognized in AOCI	—	—	—	—	—
Amount of (Gain) Loss Reclassified from AOCI					
Regulatory Assets/(Liabilities), Net (a)	(0.2)	—	—	—	(0.2)
Interest Expense	—	(2.1)	—	—	(2.1)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.2)	(2.1)	—	—	(2.3)
Income Tax (Expense) Credit	(0.1)	(0.7)	—	—	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.1)	(1.4)	—	—	(1.5)
Net Current Period Other Comprehensive Loss	(0.1)	(1.4)	—	—	(1.5)
Balance in AOCI as of December 31, 2014	$ —	$ 5.6	$ 58.4	$ (58.4)	$ 5.6

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges		
	Commodity	Interest Rate	Total
		(in millions)	
Balance in AOCI as of December 31, 2015	$ —	$ 4.2	$ 4.2
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	—	(1.2)	(1.2)
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	(1.2)	(1.2)
Income Tax (Expense) Credit	—	(0.4)	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	(0.8)	(0.8)
Net Current Period Other Comprehensive Loss	—	(0.8)	(0.8)
Balance in AOCI as of December 31, 2016	$ —	$ 3.4	$ 3.4

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedges		
	Commodity	Interest Rate	Total
		(in millions)	
Balance in AOCI as of December 31, 2014	$ —	$ 5.0	$ 5.0
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense	—	(1.2)	(1.2)
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	(1.2)	(1.2)
Income Tax (Expense) Credit	—	(0.4)	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	(0.8)	(0.8)
Net Current Period Other Comprehensive Loss	—	(0.8)	(0.8)
Balance in AOCI as of December 31, 2015	$ —	$ 4.2	$ 4.2

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2014

	Cash Flow Hedges		
	Commodity	Interest Rate	Total
		(in millions)	
Balance in AOCI as of December 31, 2013	$ 0.1	$ 5.7	$ 5.8
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Regulatory Assets/(Liabilities), Net (a)	(0.1)	—	(0.1)
Interest Expense	—	(1.1)	(1.1)
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.1)	(1.1)	(1.2)
Income Tax (Expense) Credit	—	(0.4)	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(0.1)	(0.7)	(0.8)
Net Current Period Other Comprehensive Loss	(0.1)	(0.7)	(0.8)
Balance in AOCI as of December 31, 2014	$ —	$ 5.0	$ 5.0

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2015	$ —	$ (9.1)	$ 2.6	$ (2.9)	$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI					
Interest Expense	—	2.7	—	—	2.7
Amortization of Prior Service Cost (Credit)	—	—	(1.8)	—	(1.8)
Amortization of Actuarial (Gains)/Losses	—	—	0.7	—	0.7
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	2.7	(1.1)	—	1.6
Income Tax (Expense) Credit	—	1.0	(0.4)	—	0.6
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	1.7	(0.7)	—	1.0
Net Current Period Other Comprehensive Income (Loss)	—	1.7	(0.7)	(1.0)	—
Balance in AOCI as of December 31, 2016	$ —	$ (7.4)	$ 1.9	$ (3.9)	$ (9.4)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2015

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2014	$ —	$ (11.1)	$ 3.6	$ —	$ (7.5)
Change in Fair Value Recognized in AOCI	—	—	—	(2.9)	(2.9)
Amount of (Gain) Loss Reclassified from AOCI					
Interest Expense	—	3.1	—	—	3.1
Amortization of Prior Service Cost (Credit)	—	—	(1.9)	—	(1.9)
Amortization of Actuarial (Gains)/Losses	—	—	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Credit	—	3.1	(1.5)	—	1.6
Income Tax (Expense) Credit	—	1.1	(0.5)	—	0.6
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	2.0	(1.0)	—	1.0
Net Current Period Other Comprehensive Income (Loss)	—	2.0	(1.0)	(2.9)	(1.9)
Balance in AOCI as of December 31, 2015	$ —	$ (9.1)	$ 2.6	$ (2.9)	$ (9.4)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2014

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2013	$ —	$ (13.3)	$ 4.5	$ 0.3	$ (8.5)
Change in Fair Value Recognized in AOCI	—	—	—	(0.3)	(0.3)
Amount of (Gain) Loss Reclassified from AOCI					
Regulatory Assets/(Liabilities), Net (a)	(0.1)	—	—	—	(0.1)
Interest Expense	—	3.5	—	—	3.5
Amortization of Prior Service Cost (Credit)	—	—	(1.9)	—	(1.9)
Amortization of Actuarial (Gains)/Losses	—	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Credit	(0.1)	3.5	(1.4)	—	2.0
Income Tax (Expense) Credit	(0.1)	1.3	(0.5)	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	—	2.2	(0.9)	—	1.3
Net Current Period Other Comprehensive Income (Loss)	—	2.2	(0.9)	(0.3)	1.0
Balance in AOCI as of December 31, 2014	$ —	$ (11.1)	$ 3.6	$ —	$ (7.5)

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

4. RATE MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. The Registrants' recent significant rate orders and pending rate filings are addressed in this note.

APCo and WPCo Rate Matters (Applies to AEP and APCo)

2016 West Virginia Expanded Net Energy Cost Filing

In June 2016, the WVPSC approved a settlement agreement related to APCo and WPCo's combined annual ENEC filing. The settlement agreement included $38 million ($30 million related to APCo) of additional ENEC revenues and $17 million ($14 million related to APCo) in construction surcharges annually for two years, effective July 2016. Additionally, APCo and WPCo agreed that a general rate case will not be filed before April 2018.

West Virginia Deferred Base Rate Increase

In May 2015, the WVPSC issued an order on APCo and WPCo's combined base rate case. The order included a delayed billing of $25 million ($22 million related to APCo) of the annual base rate increase to residential customers until July 2016. In June 2016, the WVPSC issued an order that approved recovery of the total deferred billing, including carrying charges through June 2018, totaling $29 million ($27 million related to APCo). Recovery was approved over two years, effective July 2016. Additionally, at the end of the two-year amortization, any over/under-recovery of the delayed billing will be included in the annual ENEC filing. The WVPSC also approved implementation of the prospective $25 million base rate increase effective July 2016.

2015 Virginia Regulatory Asset Proceeding

In 2015, the Virginia SCC initiated a proceeding to address the treatment of APCo's authorized regulatory assets. In September 2016, the Virginia SCC issued an order that approved the continued recovery through amortization of certain regulatory assets established prior to the period of frozen rates pursuant to the amended Virginia law (see "Virginia Legislation Affecting Biennial Reviews" below).

Virginia Legislation Affecting Biennial Reviews

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

In February 2016, certain APCo industrial customers filed a petition with the Virginia SCC requesting the issuance of a declaratory order that finds the amendments to Virginia law suspending biennial reviews unconstitutional and, accordingly, directs APCo to make biennial review filings beginning in 2016. In July 2016, the Virginia SCC issued an order that denied the petition. In July 2016, the industrial customers filed an appeal of the order with the Supreme Court of Virginia. Management is unable to predict the outcome of these challenges to the Virginia legislation. If the biennial review process is reinstated in advance of March 2020, it could reduce future net income and cash flows and impact financial condition.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

Parent has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base rate proceeding. During a 2015 open meeting at the PUCT, ETT committed to file a base rate case by February 2017. In January 2017, the PUCT approved ETT's request to suspend the base rate case filing and decrease ETT's annual revenue requirement by $46 million, effective March 2017. As of December 31, 2016, AEP's share of ETT's cumulative revenues, subject to review, is estimated to be $591 million based upon interim rate increases received from 2009 through 2016. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. Management is unable to determine a range of potential losses that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters (Applies to AEP and I&M)

Indiana Amended PJM Settlement Agreement

In November 2016, the IURC issued an order that approved an amended settlement agreement between I&M and certain intervenors. This agreement amends a previously approved 2014 settlement agreement that addresses the recovery of 43.5% of certain transmission expenses through the Indiana PJM rider through 2017.

The amended agreement allows I&M to recover 100% of the Indiana jurisdictional share of these transmission expenses not recovered through base rates through the Indiana PJM rider, subject to a $109 million cap for the period January 2017 through June 2018. Beginning July 2018, I&M will be allowed to recover 100% of the Indiana jurisdictional share of these transmission expenses through the Indiana PJM rider, without a cap, until the issue is addressed by the IURC in a future proceeding, subject to the condition that I&M files a base rate case on or before January 2018. The amended agreement also provides for deferral of incremental vegetation management expenses over the period January 2017 through June 2018. Any vegetation management expenses deferred would reduce the cap for the transmission expenses described above. As part of the amended settlement, I&M agreed that it will not file a base rate case before July 2017 and will not implement new base rates prior to July 2018.

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. 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 life and other related expenses. I&M proposed recovery of these costs using the existing Clean Coal Technology Rider. The AEGCo ownership share of the proposed SCR project will be billable under the Rockport Unit Power Agreement to affiliates, including I&M, with I&M's share recoverable in its base rates. 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 lease. A hearing at the IURC is scheduled for March 2017.

KGPCo Rate Matters (Applies to AEP)

Kingsport Base Rate Case

In August 2016, the TRA approved a settlement agreement that included an $8 million annual increase in base rates with a 9.85% return on common equity, effective September 2016.

OPCo Rate Matters (Applies to AEP and OPCo)

Ohio Global Settlement

In February 2017, the PUCO approved a settlement agreement (Global Settlement) filed by OPCo in December 2016. The parties to the Global Settlement include OPCo, the PUCO staff and various intervenors. The Global Settlement resolves all remaining open issues on remand from the Ohio Supreme Court in OPCo's 2009 - 2011 and June 2012 - May 2015 ESP filings, including issues related to carrying charges on the PIRR and issues related to the RSR capacity charges. It also resolves all open issues in OPCo's 2009, 2014 and 2015 SEET filings and 2009, 2012 and 2013 Fuel Adjustment Clause Audits.

The significant components of the Global Settlement include:

Remands Related to the PIRR

All applicable parties participating in this settlement will withdraw their pending applications for rehearing of the PUCO order that allowed for the reinstatement of the equity portion of the WACC rate on previously deferred fuel balances. As part of the Global Settlement, the PIRR rate to be collected from customers through December 2018 will be reduced by $97 million.

Remands Related to the RSR

Beginning January 2017, OPCo will be entitled to collect $388 million in RSR revenues over a total of 30 months, subject to true up at the end of the collection period in June 2019. Current RSR rates will continue until the new RSR rates are approved. The Global Settlement resolves the issues related to the non-deferral portion of RSR collections and the impact of the appropriate energy credit on capacity charges. In December 2016, OPCo recorded an increase in Regulatory Assets on the balance sheets for the deferral of $83 million in RSR capacity costs and $14 million in related debt carrying charges with a corresponding decrease in expense in Generation Deferrals and an increase in Carrying Costs Income, respectively, on the statements of income.

For the year ended December 31, 2016, AEP recorded approximately $97 million in RSR capacity deferrals and related carrying charges to the following line items on the statements of income:

	AEP (in millions)	
Fuel and Other Consumables Used for Electric Generation	$	(19.0)
Purchased Electricity for Resale		(19.9)
Other Operation		(15.7)
Depreciation and Amortization		(42.1)
Total Decrease in RSR Expenses	$	(96.7)

As of December 31, 2016, OPCo's total RSR under-recovery balance, including carrying charges, was $299 million.

Remands Related to the SEET

As part of the Global Settlement,$20 million will be returned to customers over a 12-month period commencing within 45 days of the final PUCO order adopting the Global Settlement. The Global Settlement states that this obligation has no precedential effect on OPCo's SEET methodology. In addition, the parties agreed that earnings were not significantly excessive in 2015. In December 2016, OPCo accrued $20 million in Other Current Liabilities on the balance sheets with a corresponding decrease in Electricity, Transmission and Distribution revenues (Transmission and Distribution Utilities for AEP) on the statements of income. The Global Settlement resolves the issues related to the 2014 and 2015 SEET proceedings.

Fuel Adjustment Clause Proceedings

OPCo will refund $100 million paid by SSO customers from August 2012 - May 2015 related to OVEC and Lawrenceburg purchases. In December 2016, OPCo accrued $100 million in Other Current Liabilities on the balance sheets with a corresponding decrease in Electricity, Transmission and Distribution revenues (Transmission and Distribution Utilities for AEP) on the statements of income. The Global Settlement resolves the claimed recovery of fixed fuel costs through both the FAC and the approved capacity charges. This refund will be a one-time credit that will be applied the earlier of either 45 days after the final non-appealable order from the PUCO adopting the Global Settlement, or the December 2017 billing cycle.

Ohio Electric Security Plan Filings

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018.

In 2012, the PUCO issued an order in a separate proceeding which implemented a PIRR to recover OPCo's deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo appealed that PUCO order to the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated 2009 - 2011 ESP order, which granted a WACC rate. In 2015, the Supreme Court of Ohio issued a decision that reversed the PUCO order on the carrying cost rate issue and remanded the matter back to the PUCO for reinstatement of the WACC rate. In June 2016, the PUCO approved OPCo's proposed increase to the PIRR rates, in accordance with the Supreme Court of Ohio ruling. The increase to PIRR rates included $146 million in additional carrying charges and the recovery of $40 million in additional under-recovered fuel costs resulting from a decrease in customer demand. The increase is effective July 2016 through December 2018. In July 2016, intervenors filed requests for rehearing with the PUCO, which the PUCO granted in August 2016. In December 2016, OPCo filed a Global Settlement with the PUCO related to this issue. See "Ohio Global Settlement" section above.

June 2012 – May 2015 ESP Including Capacity Charge

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

In July 2012, the PUCO issued an order in a separate capacity proceeding requiring OPCo to charge CRES providers the RPM price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The OPCo RPM price collected from CRES providers, which included reserve margins, was approximately $34/MW day through May 2014 and $150/MW day from June 2014 through May 2015. In April 2016, the Supreme Court of Ohio issued two opinions related to the deferral of OPCo's capacity charges. In one of the opinions, the Supreme Court of Ohio ruled that the PUCO must reconsider an energy credit that was used to determine OPCo's authorized capacity deferral threshold of $188.88/MW day during the August 2012 through May 2015 period.

The PUCO reduced OPCo's authorized capacity deferral threshold to $188.88/MW day largely due to an offset for an energy credit of $147.41/MW day. The Supreme Court of Ohio directed the PUCO to substantively address OPCo's arguments that the $147.41/MW day credit was overstated by approximately $100/MW day due to various inaccuracies affecting input data and assumptions. See "Ohio Global Settlement" section above.

As part of the August 2012 ESP order, the PUCO established a non-bypassable RSR, effective September 2012. The RSR was collected from customers at $3.50/MWh through May 2014 and at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April 2015, the PUCO issued an order that modified and approved OPCo's July 2014 application to collect the unrecovered portion of the deferred capacity costs. The order included approval to continue the collection of deferred capacity costs at a rate of $4.00/MWh beginning June 1, 2015 for approximately 32 months, with carrying costs at a long-term cost of debt rate. Additionally, the order stated that an audit will be conducted of the May 31, 2015 capacity deferral balance. As of December 31, 2016, OPCo's net deferred capacity costs balance was $202 million, including debt carrying costs, and was recorded in Regulatory Assets on the balance sheets. In April 2016, the second Supreme Court of Ohio opinion rejected a portion of OPCo's RSR revenues collected during the period September 2012 through May 2015 and directed the PUCO to reduce OPCo's deferred capacity costs by these previously collected RSR revenues. The Supreme Court of Ohio was not able to determine the amount of the reduction to OPCo's deferred capacity costs and remanded the issue to the PUCO to determine the appropriate reduction. As directed by the PUCO, in May 2016, OPCo submitted revised RSR tariffs that reflect the RSR being collected subject to refund. See "Ohio Global Settlement" section above.

In April 2016, the Supreme Court of Ohio also ruled favorably on OPCo's cross-appeal regarding a previously PUCO-imposed SEET threshold under the ESP and remanded this issue to the PUCO. See "Ohio Global Settlement" section above and "Significantly Excessive Earnings Test Filings" section below.

In 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings.

In 2014, the PUCO denied all rehearing requests, agreed to issue a supplemental request for an independent auditor in the 2012 - 2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC, and approved OPCo's request to implement riders related to the unbundling of the FAC. In October 2014, the independent auditor, selected by the PUCO, filed its report with the PUCO for the period August 2012 through May 2015. If the PUCO ultimately concludes that a portion of the fixed fuel costs are also recovered through OPCo's $188.88/MW day capacity charge, the independent auditor has recommended a methodology for calculating a refund of a portion of certain fixed fuel costs. The retail share of these fixed fuel costs is approximately $90 million annually. See "2012 and 2013 Fuel Adjustment Clause Audits" section below.

In June 2016, OPCo filed a request with the PUCO that requested a consolidated procedural schedule to resolve interrelated proceedings including (a) OPCo's deferral of capacity costs for the period August 2012 through May 2015, (b) the implementation of OPCo's RSR and (c) the concerns related to the recovery of fixed fuel costs through both the FAC and the approved capacity charges. As part of the filing, and due to the interrelated nature of the two Supreme Court of Ohio opinions that directly relate to OPCo's deferred capacity costs, OPCo requested that its net deferred capacity costs balance as of May 31, 2015 increase by $157 million, including carrying charges through September 2016. This net increase consists of a $327 million decrease due to the non-deferral portion of the RSR collections and an increase of $484 million for the correction of the energy credit. Additionally, OPCo filed testimony supporting the position that double recovery of fixed fuel costs could not have occurred because OPCo was unable to fully recover its capacity costs, which included fixed fuel costs, even with a corrected energy credit. In December 2016, OPCo filed a Global Settlement with the PUCO related to these issues. See "Ohio Global Settlement" section above.

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

In 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. The proposal also included a PPA rider that would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA. The PPA would initially be based upon the OVEC contractual entitlement and could, upon further approval, be expanded to include other contracts involving other Ohio legacy generation assets.

In February 2015, the PUCO issued an order approving OPCo's ESP application, subject to certain modifications, with a return on common equity of 10.2% on capital costs for certain riders. The order included (a) approval of the DIR, with modified rate caps established by the PUCO, (b) authorization to establish a zero rate rider for OPCo's proposed PPA, (c) the option for OPCo to reapply in a future proceeding with a more detailed PPA proposal and (d) a directive to continue to pursue the transfer of the OVEC contractual entitlement to AGR or to otherwise divest of its interest in OVEC. In May 2015, the PUCO issued an order on rehearing that increased the DIR rate caps and deferred ruling on all requests for rehearing related to the establishment of the PPA rider. In July 2015, the PUCO granted OPCo's and various intervenors' requests for rehearing related to the May 2015 order. In November 2016, the PUCO issued an additional order on rehearing that approved the DIR caps with additional amendments and denied the remaining requests for rehearing. In January 2017, the PUCO granted intervenors requests for rehearing that oppose the PPA rider as well as the amended DIR caps.

In May 2015, OPCo filed an amended PPA application that (a) included OPCo's OVEC contractual entitlement (OVEC PPA), (b) addressed the PPA requirements set forth in the PUCO's February 2015 order and (c) included the 2,671 MWs to be available for capacity, energy and ancillary services, produced by AGR over the lives of the respective generating units (Affiliate PPA).

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 effective April 2016 through May 2024, subject to audit and review by the PUCO. The stipulation agreement, as approved, included (a) an Affiliate PPA between OPCo and AGR to be included in the PPA rider, (b) OPCo's OVEC PPA to be included in the PPA rider, (c) potential additional contingent customer credits of up to $100 million to be included in the PPA rider over the final four years of the PPA rider and (d) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MWs and a wind energy project(s) of at least 500 MWs, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects. In December 2016, in accordance with the stipulation agreement, OPCo filed a carbon reduction plan that focused on fuel diversification and carbon emission reductions.

In April 2016, the FERC issued an order granting a January 2016 complaint filed against AGR and OPCo. The FERC order rescinded the waivers of the FERC's affiliate rules as to the affiliate PPA between AGR and OPCo. As a result, AGR and OPCo cannot implement the affiliate PPA without the FERC review, in accordance with FERC's rules governing affiliate transactions. As a result of the April 2016 FERC order, management does not intend to pursue the affiliate PPA.

In May 2016, OPCo filed an application for rehearing with the PUCO related to certain aspects of the March 2016 PUCO order. The application included a proposed OVEC-only PPA Rider to recover the net margin after sales through PJM and included an option for the rider to be bypassable. The proposed OVEC-only PPA Rider included (a) the elimination of the PUCO-imposed customer-specific rate impact cap of 5% through May 2018, (b) modifications to decrease the amount of the potential customer credits and (c) the inclusion of PJM capacity performance penalties within the PPA rider. Also in May 2016, intervenors filed applications for rehearing with the PUCO opposing the modified and approved stipulation agreement. In November 2016, the PUCO issued an order on rehearing that approved recovery of the OVEC-related net margin incurred from June 2016 through the term of the PPA rider and the modification to reduce the customer credits to $15 million as requested by OPCo. The PUCO rejected OPCo's request to eliminate both the 5% rate impact cap and the inclusion of the capacity performance penalties within the PPA rider. In January

2017, the PUCO granted, for further consideration, intervenors additional applications for rehearing that included arguments that opposed the OVEC-only PPA and stated that the stipulation agreement approved in March 2016 does not provide customers with rate stability.

OPCo has the option to exercise its right to withdraw from the PPA stipulation if the PUCO makes unacceptable modifications to the stipulation, including modifications as part of the pending rehearing.

Consistent with the terms of the 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 Distribution Technology Rider and a Renewable Resource Rider.

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.

Significantly Excessive Earnings Test Filings

Background

Ohio law provides for the return of significantly excessive earnings to ratepayers upon PUCO review. Significantly excessive earnings are measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk.

2009 SEET Filing

In 2011, the PUCO issued an order on the 2009 SEET filing. The order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another project.

In September 2013, a proposed second phase of OPCo's *gridSMART®* (*gridSMART®* Phase II) program was filed with the PUCO which included a proposed project to satisfy the PUCO 2009 SEET directive. In April 2016, a stipulation agreement related to the *gridSMART®* Phase II program was filed with the PUCO. As part of the stipulation agreement, OPCo will invest at least $20 million over a six-year period for the installation of Volt VAR Optimization (VVO) technology on selected circuits throughout OPCo's service territory. All parties to the stipulation agree that OPCo's proposed VVO investment resolves OPCo's outstanding obligation for renewable or similar investment associated with the PUCO's 2009 SEET directive. As a part of the December 2016 Global Settlement, OCC agreed to no longer contest the *gridSMART®* Phase II stipulation. In February 2017, the PUCO approved the *gridSMART®* Phase II stipulation agreement. See "Ohio Global Settlement" section above.

2014 and 2015 SEET Filings

The PUCO established an annual SEET earnings threshold of 12% during the June 2012 - May 2015 ESP period. In May 2013, OPCo filed a cross appeal with the Supreme Court of Ohio, asserting that the SEET threshold was not based on the earnings of comparable publicly traded companies as originally required by the SEET statute.

In April 2016, the Supreme Court of Ohio agreed with OPCo's cross-appeal assertion that a 12% SEET threshold was not based on the applicable Ohio SEET statute. The Supreme Court of Ohio reversed the 12% threshold and remanded this issue to the PUCO.

In June 2015 and May 2016, OPCo submitted its SEET filings for 2014 and 2015, respectively, with the PUCO. In August 2016, intervenors filed testimony recommending a revenue refund of approximately $20 million for 2014 and no refund for 2015 based upon a new approach to determine significantly excessive earnings that has not been previously approved by the PUCO. In September 2016, OPCo and the PUCO staff filed a stipulation agreement with the PUCO stating that no significantly excessive earnings occurred for 2014 or 2015. In September 2016, intervenors filed testimony opposing the stipulation agreement. See "Ohio Global Settlement" section above.

2016 SEET Filing

OPCo expects to submit its 2016 SEET filing in the second quarter of 2017. OPCo's 2016 SEET provision was determined by excluding the gain on the deferral of RSR costs related to the Global Settlement. In addition, refunds to customers included in the Global Settlement relating to the SEET remands and fuel adjustment clause proceedings were excluded from the determination of the 2016 SEET provision. Management believes its financial statements adequately address the impact of 2016 SEET requirements. If the PUCO adopts a different 2016 SEET methodology, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

In January 2012, the PUCO issued an order in OPCo's 2009 FAC that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. As a result, OPCo recorded a $30 million net favorable adjustment on the statements of income in 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. In 2014, the Supreme Court of Ohio upheld the PUCO order on appeal. See "Ohio Global Settlement" section above.

2012 and 2013 Fuel Adjustment Clause Audits

In May 2014, the PUCO-selected outside consultant provided its final report related to its 2012 and 2013 FAC audit which included certain unfavorable recommendations related to the FAC recovery for 2012 and 2013. These recommendations are opposed by OPCo. In addition, the PUCO will consider the results of the final audit of the recovery of fixed fuel costs that was issued in October 2014. See the "June 2012 - May 2015 ESP Including Capacity Charge" and "Ohio Global Settlement" sections above.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo. In OPCo's 2009 - 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues. Through September 2009, the last month of the interim arrangement, OPCo had approximately $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo's filing to approve recovery of the deferral under the interim agreement. Of the $64 million in deferred FAC costs, approximately 50% was related to Columbus Southern Power Company (CSPCo) and 50% related to OPCo, prior to the merger of CSPCo into OPCo in December 2011. CSPCo's portion of these deferred fuel costs has been recovered as a result of the previous collections of CSPCo fuel costs from ratepayers and the PUCO's 2013 order to apply CSPCo's 2010 excessive earnings to offset CSPCo's final deferred fuel balance. OPCo's share of Ormet deferred fuel costs continues to be recovered through OPCo's PIRR.

The Ohio Global Settlement discussed above, approved by the PUCO in February 2017, includes the resolution of the 2009, 2012 and 2013 Fuel Adjustment Clause Audits together with the finalization of the PIRR. The resolution of those cases effectively makes the risk of non-recovery of the Ormet deferrals remote.

<u>PSO Rate Matters</u> (Applies to AEP and PSO)

2015 Oklahoma Base Rate Case

In July 2015, PSO filed a request with the OCC to increase annual revenues by $137 million. The request consisted of (a) a base rate increase of $89 million, which includes $48 million in increased depreciation expense that reflects, among other things, recovery through June 2026 of Northeastern Plant, Units 3 and 4, (b) a rider or base rate increase of $44 million to recover costs for the environmental controls being installed on Northeastern Plant, Unit 3 and the Comanche Plant and (c) a request to include environmental consumable costs in the FAC, estimated to be $4 million annually. The rate increase included a proposed return on common equity of 10.5%. The $44 million increase related to environmental investments was proposed to be effective in March 2016, after the Northeastern Plant, Unit 3 environmental controls were placed in service. The total estimated cost of the environmental controls to be installed at Northeastern Plant, Unit 3 and the Comanche Plant is $219 million, excluding AFUDC. As of December 31, 2016, PSO had incurred costs of $181 million and $44 million, including AFUDC, for Northeastern Plant, Unit 3 and Comanche Plant, respectively. In January 2016, PSO implemented an interim annual base rate increase of $75 million, subject to refund.

In addition, the filing also notified the OCC that the incremental replacement capacity and energy costs, including the first year effects of new PPAs, estimated to be $35 million, will be incurred related to the environmental compliance plan due to the closure of Northeastern Plant, Unit 4, which would be recovered through the FAC. In April 2016, Northeastern Plant, Unit 4 was retired. Upon retirement, $87 million was reclassified as Regulatory Assets on the balance sheets related to the net book value of Northeastern Plant, Unit 4. These regulatory assets are pending regulatory approval.

In November 2016 and December 2016, the OCC issued orders that approved a net annual revenue increase of $19 million based upon a 9.5% return on common equity. The orders also included (a) approval to defer incurred costs related to PSO's environmental compliance plan until those costs are included in base rates, (b) no determination related to the return of and return on the post-retirement remaining net book value of Northeastern Plant, Unit 4 since the April 2016 retirement was outside of the test year, (c) approval to include environmental consumable costs in the FAC (d) the continued depreciation of Northeastern Plant, Units 3 and 4 through 2040 (no accelerated depreciation) and (e) altered the system reliability rider by eliminating the expense portion of the rider and setting the capital portion of the rider at the December 2016 plant balance and approved recovery of deferred expenses and return on the capital balance incurred prior to the effective date of new tariffs in January 2017. Additionally, the orders stated that the cost recovery of new PPAs related to replacement power resulting from the retirement of Northeastern Plant, Unit 4 will be addressed in a future FAC proceeding. Effective December 2016, interim rates were terminated and the refund of over collections began and will be completed no later than October 2017. In accordance with the final order, updated rates and tariffs went into effect in January 2017.

If any of these costs, including a return on Northeastern Plant, Unit 4, are ultimately not recoverable, it could reduce future net income and cash flows and impact financial condition.

<u>SWEPCo Rate Matters</u> (Applies to AEP and SWEPCo)

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2.

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. The resulting annual base rate increase was approximately $52 million. In 2014, intervenors filed appeals of that order with the Texas District Court and SWEPCo intervened in those appeals. A hearing at the Texas District Court is scheduled for March 2017.

If certain parts of the PUCT order are overturned or if SWEPCo cannot ultimately recover its Texas jurisdictional share of the Turk Plant investment, including AFUDC, it could reduce future net income and cash flows and impact financial condition.

2016 Texas Base Rate Case

In December 2016, SWEPCo filed a base rate request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. The annual increase includes approximately (a) $34 million related to additional environmental controls to comply with Federal EPA mandates, (b) $25 million for additional generation, transmission and distribution investments and increased operating costs, (c) $8 million related to transmission cost recovery within SWEPCo's regional transmission organization and (d) $2 million in additional vegetation management.

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

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was approved by the LPSC. The settlement increased SWEPCo's Louisiana total rates by approximately $2 million annually, effective March 2013, which consisted of an increase in base rates of approximately $85 million annually offset by a decrease in fuel and other rates of approximately $83 million annually. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit. The rates are subject to refund based on the prudence review of the Turk Plant. The settlement also provided that the LPSC would review base rates in 2014 and 2015 and that SWEPCo would recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In December 2014, the LPSC approved a settlement agreement related to the staff review of the cost of service. The settlement agreement reduced the requested revenue increase by $3 million, primarily due to the timing of both the allowed recovery of certain existing regulatory assets and the establishment of a regulatory asset for certain previously expensed costs. A hearing at the LPSC related to the Turk Plant prudence review is scheduled for June 2017. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition.

2014 Louisiana Formula Rate Filing

In 2014, SWEPCo filed its annual formula rate plan for test year 2013 with the LPSC. The filing included a $5 million annual increase, which was effective August 2014. SWEPCo also proposed to increase rates by an additional $15 million annually, effective January 2015, for a total annual increase of $20 million. This additional increase reflects the cost of incremental generation used to serve Louisiana customers in 2015 due to the expiration of a purchased power agreement attributable to Louisiana customers. In December 2014, the LPSC approved a partial settlement agreement that included the implementation of the $15 million annual increase in rates effective January 2015, subject to staff review of the cost of service and prudence review of the Turk Plant. In July 2016, the LPSC approved a settlement agreement related to the staff review of the cost of service. A portion of the rates remain subject to refund based on the prudence review of the Turk Plant. See "2012 Louisiana Formula Rate Filing" above. Management believes its financial statements adequately address the impact of this settlement agreement. If the LPSC orders refunds based upon the pending prudence review of the Turk Plant investment, it could reduce future net income and cash flows and impact financial condition.

2015 Louisiana Formula Rate Filing

In April 2015, SWEPCo filed its formula rate plan for test year 2014 with the LPSC. The filing included a $14 million annual increase, which was effective August 2015. This increase is subject to LPSC staff review and is subject to refund. If any of these costs are not recoverable, 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 cost a total of approximately $850 million, excluding AFUDC. As of December 31, 2016, SWEPCo had incurred costs of $397 million, including AFUDC, and had remaining contractual construction obligations of $11 million related to these projects. As part of this investment, in 2016 SWEPCo completed construction of environmental control projects to meet Mercury and Air Toxics Standards for Welsh Plant, Units 1 and 3 at a cost of approximately $370 million, excluding AFUDC. Management continues to evaluate the impact of environmental rules and related project cost estimates. In March 2016, SWEPCo filed a request with the APSC to recover $69 million in environmental costs related to the Arkansas retail jurisdictional share of Welsh Plant, Units 1 and 3, which was approved by the APSC in August 2016. SWEPCo began recovering the Arkansas jurisdictional share of these costs in March 2016, subject to review in the next filed base rate proceeding. In September 2016, SWEPCo filed an additional request to increase the Arkansas retail jurisdictional share of the environmental investment by $10 million, for a total of $79 million. SWEPCo implemented the increase in September 2016. In December 2016, the LPSC approved deferral of certain expenses related to environmental controls installed at Welsh Plant, until these investments are put into base rates. The eligible Welsh Plant deferrals through December 31, 2016 are $8 million, excluding $5 million of unrecognized equity, subject to review by the LPSC, and include a WACC return on environmental investments and the related depreciation expense and taxes. SWEPCo will seek recovery of its project costs from customers at the state commissions and the FERC.

As of December 31, 2016, the net book value of Welsh Plant, Units 1 and 3 was $633 million, before cost of removal, including materials and supplies inventory and CWIP. In April 2016, Welsh Plant, Unit 2 was retired. Upon retirement, $76 million was reclassified as Regulatory Assets on the balance sheets related to the net book value of Welsh Plant, Unit 2 and the related asset retirement obligation costs. In SWEPCo's 2016 Texas Base Rate Case, SWEPCo requested recovery of the Texas jurisdictional share (approximately 33%) of the net book value of Welsh Plant, Unit 2 through 2042, the remaining life of Welsh Plant, Unit 3. Management will seek recovery of the remaining Welsh Plant, Unit 2 retirement-related regulatory assets in future rate proceedings.

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

<u>AEP Texas Rate Matters</u> (Applies to AEP)

TCC and TNC Merger

Effective December 31, 2016, TCC and TNC merged into AEP Utilities, Inc., as approved by the FERC and the PUCT in September 2016 and December 2016, respectively. Upon merger, AEP Utilities, Inc. changed its name to AEP Texas Inc., but maintained TCC's and TNC's respective customer rates. The PUCT ordered certain post-merger conditions which included a) the sharing of certain interest rate savings with customers and b) an annual credit to customers of approximately $630 thousand for savings resulting from an expected reduction in post-merger debt issuance costs, effective until the next base rate case.

AEP Texas Distribution Cost Recovery Factor (DCRF)

In July 2016, the PUCT approved settlement agreements between TCC, TNC and intervenors related to requests for DCRF riders to allow recovery of eligible net distribution investments. The settlement agreement included an annual revenue requirement of $56 million ($45 million for the TCC division and $11 million for the TNC division), effective September 2016. Amounts approved are subject to refund based upon a prudence review of the investments in AEP Texas' next base rate case.

<u>FERC Rate Matters</u> (Applies to AEP, APCo, I&M and OPCo)

PJM Transmission Rates

In June 2016, PJM transmission owners, including the AEP East Companies, and various state commissions filed a settlement agreement with the FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. In July 2016, certain parties filed comments at the FERC contesting the settlement agreement. Upon final FERC approval, PJM would implement a transmission enhancement charge adjustment through the PJM OATT, billable through 2025. Management expects that any refunds received would generally be returned to retail customers through existing state rider mechanisms.

FERC Transmission Complaint and Proposed Modifications to Transmission Rates

In October 2016, several parties filed a joint complaint with the FERC claiming that the base return on common equity used by various AEP affiliates 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. In November 2016, AEP affiliates filed an application with the FERC to modify the FERC formula transmission rate calculation, including adjustments for certain tax issues and a shift from historical to estimated expenses with a proposed effective date of January 1, 2017. The rates will be implemented based upon the date provided in the pending FERC order, subject to refund. Management believes its financial statements adequately address the impact of the complaint and the proposed modifications to AEP's transmission rates in PJM. 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.

<u>Other Rate Matters</u> (Applies to AEP, PSO and SWEPCo)

SPP OATT Upgrade Costs

Under the SPP OATT, costs of sponsor-funded transmission upgrades may be recovered, in part, from SPP customers whose transmission service is dependent upon capacity enabled by the upgrades. Prior to 2016, SPP had not charged its customers any amounts attributable to these upgrades. In November 2016, SPP billed transmission service customers, including PSO and SWEPCo, for upgrade costs incurred since 2008. SPP then credited the qualifying transmission upgrade owners, including SWEPCo, for the use of these upgrades. In 2016, PSO and SWEPCo recognized a net unfavorable impact of approximately $3 million and $4 million, respectively, related to the OATT upgrade costs.

5. EFFECTS OF REGULATION

The disclosures in this note apply to all Registrants unless indicated otherwise.

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining Recovery Period
	2016	2015	
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 61.4	$ 38.9	1 year
Under-recovered Fuel Costs - does not earn a return	95.2	76.3	1 year
Total Current Regulatory Assets	$ 156.6	$ 115.2	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 159.9	$ —	
Ohio Capacity Deferral	96.7	—	
Storm Related Costs	25.1	24.2	
Plant Retirement Costs - Materials and Supplies	9.1	20.9	
Other Regulatory Assets Pending Final Regulatory Approval	1.3	—	
Regulatory Assets Currently Not Earning a Return			
Cook Plant Uprate Project	36.3	—	
Plant Retirement Costs - Asset Retirement Obligation Costs	29.6	59.8	
Storm Related Costs	25.9	18.2	
Environmental Control Projects	24.1	—	
Cook Plant Turbine	12.8	9.7	
Peak Demand Reduction/Energy Efficiency	0.2	13.1	
Other Regulatory Assets Pending Final Regulatory Approval	29.1	22.0	
Total Regulatory Assets Pending Final Regulatory Approval (b)	450.1	167.9	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	550.6	539.3	28 years
Ohio Phase-In Recovery Rider	218.9	304.5	2 years
Ohio Capacity Deferral	201.9	358.7	2 years
Meter Replacement Costs	99.9	90.4	11 years
Ohio Distribution Decoupling	41.8	37.5	2 years
Advanced Metering System	20.9	3.6	4 years
Basic Transmission Cost Rider	19.9	—	2 years
West Virginia Delayed Customer Billing	19.5	—	2 years
Asset Removal Costs	18.7	38.1	(a)
Mitchell Plant Transfer	18.5	19.3	24 years
Plant Retirement Costs - Asset Retirement Obligation Costs	18.3	7.6	24 years
Storm Related Costs	15.3	8.8	3 years
Red Rock Generating Facility	9.1	9.3	40 years
Ohio Transmission Cost Recovery Rider	—	12.3	
Other Regulatory Assets Approved for Recovery	27.6	25.5	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net (c)	1,575.0	1,385.3	62 years
Pension and OPEB Funded Status	1,516.2	1,410.5	12 years
Unamortized Loss on Reacquired Debt	137.8	148.7	29 years
Unrealized Loss on Forward Commitments	119.1	10.7	16 years
Cook Plant Nuclear Refueling Outage Levelization	75.2	26.8	3 years
Storm Related Costs	58.7	94.6	4 years
Peak Demand Reduction/Energy Efficiency	49.9	33.3	5 years
Plant Retirement Costs - Asset Retirement Obligation Costs	48.9	58.0	24 years
Postemployment Benefits	39.1	42.6	5 years
Virginia Transmission Rate Adjustment Clause	38.7	74.6	2 years
Medicare Subsidy	37.2	41.8	8 years
Vegetation Management	31.4	36.9	5 years
Off-system Sales Margin Sharing - Indiana	24.3	6.8	2 years
OVEC Purchased Power	22.1	—	2 years

United Mine Workers of America Pension Withdrawal	20.2	14.4	6 years
Deferred System Reliability Rider Expenses	12.5	9.9	1 year
SPP Base Plan Fees	10.7	—	2 years
Carbon Capture and Storage Product Validation Facility	9.1	11.7	4 years
IGCC Pre-Construction Costs	8.6	10.9	24 years
Transmission Cost Recovery Factor	5.3	9.9	1 year
Distribution Investment Rider	2.0	12.3	2 years
Other Regulatory Assets Approved for Recovery	52.5	77.8	various
Total Regulatory Assets Approved for Recovery	5,175.4	4,972.4	
Total Noncurrent Regulatory Assets	$ 5,625.5	$ 5,140.3	

(a) As a regulated entity, removal costs accrued are typically recorded as regulatory liabilities when removal costs accrued exceed actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. As of December 31, 2016, KPCo's accumulated actual removal cost incurred exceeded accumulated removal cost accrued, creating an asset balance. As a result, the balance was reclassified to a regulatory asset. Within the next two years, KPCo's removal costs accrued are expected to exceed removal costs incurred resulting in a regulatory liability.
(b) As of December 31, 2016, APCo has deferred a total of $91 million as charges to accumulated depreciation related to certain plant retirements in 2015. APCo intends to address the need for depreciation rate increases in a subsequent base rate cases.
(c) Includes $320 million and $288 million as of December 31, 2016 and 2015, respectively, expected to be recovered in formula rates.

	AEP		
	December 31,		Remaining
	2016	2015	Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 3.8	$ 84.8	1 year
Over-recovered Fuel Costs - does not pay a return	4.2	29.1	1 year
Total Current Regulatory Liabilities	$ 8.0	$ 113.9	

Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	2016	2015	Remaining Refund Period
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Provision for Regulatory Loss	$ —	$ 40.6	
Other Regulatory Liabilities Pending Final Regulatory Determination	0.8	0.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	0.8	40.8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs (a)	2,627.5	2,656.5	(b)
Advanced Metering Infrastructure Surcharge	17.0	21.2	4 years
Louisiana Refundable Construction Financing Costs	16.2	37.4	2 years
Deferred Investment Tax Credits	12.6	14.7	42 years
Excess Earnings	10.0	10.6	37 years
Other Regulatory Liabilities Approved for Payment	1.6	20.5	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	731.2	636.5	(c)
Deferred Investment Tax Credits	132.9	113.3	46 years
Spent Nuclear Fuel	44.2	43.4	(c)
Transition Charges	40.5	46.5	11 years
Peak Demand Reduction/Energy Efficiency	34.0	5.3	2 years
Enhanced Service Reliability Plan	21.7	8.0	2 years
gridSMART® Costs	11.9	—	2 years
Advanced Metering Costs	11.5	11.4	1 year
Unrealized Gain on Forward Commitments	6.2	33.8	2 years
Deferred Wind Power Costs	2.1	11.8	1 year
Other Regulatory Liabilities Approved for Payment	29.4	24.4	various
Total Regulatory Liabilities Approved for Payment	3,750.5	3,695.3	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,751.3	$ 3,736.1	

(a) As of December 31, 2016, I&M also charged $43 million to asset removal costs related to various Tanners Creek Plant related assets, primarily related to the net book value of ARO assets. The Indiana and Michigan retail jurisdictions of I&M have increased depreciation rates on Rockport Plant to recover the net book value of Tanners Creek Plant that was retired in 2015. I&M intends to address the need for increases in depreciation rates to recover the deferral in its next Indiana and Michigan base rate cases.
(b) Relieved as removal costs are incurred.
(c) Relieved when plant is decommissioned.

Regulatory Assets:	APCo December 31, 2016	APCo December 31, 2015	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 6.2	$ 27.3	1 year
Under-recovered Fuel Costs - does not earn a return	62.2	59.6	1 year
Total Current Regulatory Assets	$ 68.4	$ 86.9	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Materials and Supplies	$ 9.1	$ 9.3	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	29.6	32.7	
Peak Demand Reduction/Energy Efficiency - Virginia	—	12.7	
Amos Plant Transfer Costs - West Virginia	—	2.0	
Other Regulatory Assets Pending Final Regulatory Approval	0.6	0.6	
Total Regulatory Assets Pending Final Regulatory Approval (a)	39.3	57.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant - West Virginia	85.4	86.5	27 years
West Virginia Delayed Customer Billing	18.1	—	2 years
Storm Related Costs - Virginia	4.6	8.8	2 years
RTO Formation/Integration Costs	1.6	2.1	3 years
Other Regulatory Assets Approved for Recovery	0.6	—	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net (b)	463.5	441.7	26 years
Pension and OPEB Funded Status	221.4	217.6	12 years
Unamortized Loss on Reacquired Debt	97.2	101.5	29 years
Storm Related Costs - West Virginia	47.8	63.5	4 years
Virginia Transmission Rate Adjustment Clause	38.7	74.6	2 years
Vegetation Management Program - West Virginia	31.4	31.2	5 years
Peak Demand Reduction/Energy Efficiency	19.2	3.5	4 years
Postemployment Benefits	17.4	19.6	5 years
Carbon Capture and Storage Product Validation Facility - West Virginia, FERC	9.1	11.7	4 years
IGCC Pre-Construction Costs - West Virginia, FERC	7.4	9.6	4 years
Virginia Generation Rate Adjustment Clause	6.5	5.2	2 years
Medicare Subsidy - West Virginia, FERC	4.7	5.3	8 years
Uncollected Accounts - West Virginia	2.7	3.5	4 years
Deferred Restructuring Costs - West Virginia	2.5	4.5	2 years
Carbon Capture and Storage Commercial Scale Facility - West Virginia, FERC	1.0	1.2	6 years
Asset Retirement Obligation	0.6	2.4	1 year
Transmission Agreement Phase-In - West Virginia	—	1.7	
Other Regulatory Assets Approved for Recovery	0.4	1.2	various
Total Regulatory Assets Approved for Recovery	1,081.8	1,096.9	
Total Noncurrent Regulatory Assets	$ 1,121.1	$ 1,154.2	

(a) As of December 31, 2016, APCo has also deferred $91 million as a charge to accumulated depreciation related to the net book value of certain plants retired in 2015, primarily in its Virginia jurisdiction. These plants were normal retirements and not abandonments. APCo intends to address the need for an increase in its Virginia depreciation rates in March 2020, as part of its 2018-2019 Virginia biennial filing.

(b) Includes $64 million and $59 million as of December 31, 2016 and 2015, respectively, expected to be recovered in formula rates.

Regulatory Liabilities:	APCo December 31, 2016	APCo December 31, 2015	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 616.9	$ 612.9	(a)
Deferred Investment Tax Credits	0.9	1.0	42 years
Regulatory Liabilities Currently Not Paying a Return			
Consumer Rate Relief - West Virginia	5.1	2.9	1 year
Deferred Wind Power Costs - Virginia	2.1	11.8	1 year
Energy Efficiency Rate Adjustment Clause - Virginia	1.5	—	2 years
Unrealized Gain on Forward Commitments	1.3	8.4	2 years
Other Regulatory Liabilities Approved for Payment	—	0.1	various
Total Regulatory Liabilities Approved for Payment	627.8	637.1	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 627.8	$ 637.1	

(a) Relieved as removal costs are incurred.

Regulatory Assets:	I&M December 31, 2016	2015	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 13.0	$ 7.5	1 year
Under-recovered Fuel Costs - does not earn a return	13.1	4.1	1 year
Total Current Regulatory Assets	$ 26.1	$ 11.6	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Materials and Supplies	$ —	$ 11.6	
Regulatory Assets Currently Not Earning a Return			
Cook Uprate Project	36.3	—	
Cook Plant Turbine	12.8	9.7	
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	8.1	4.2	
Rockport Plant Dry Sorbent Injection System - Indiana	6.6	2.8	
Plant Retirement Costs - Asset Retirement Obligation Costs - Indiana	—	27.1	
Stranded Costs on Abandoned Plants	—	3.9	
Other Regulatory Assets Pending Final Regulatory Approval	0.9	—	
Total Regulatory Assets Pending Final Regulatory Approval	64.7	59.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	252.8	260.3	28 years
Cook Plant, Unit 2 Baffle Bolts - Indiana	6.3	6.6	22 years
RTO Formation/Integration Costs	1.2	1.5	3 years
Other Regulatory Assets Approved for Recovery	1.3	1.0	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net (a)	302.6	246.8	32 years
Pension and OPEB Funded Status	141.9	126.4	12 years
Cook Plant Nuclear Refueling Outage Levelization	75.2	26.8	3 years
Off-system Sales Margin Sharing - Indiana	24.3	6.8	2 years
Postemployment Benefits	11.4	10.7	5 years
Unamortized Loss on Reacquired Debt	10.7	12.0	16 years
Medicare Subsidy	8.2	9.2	8 years
Litigation Settlement - Indiana	7.6	8.6	9 years
River Transportation Division Expenses	3.7	—	1 year
Peak Demand Reduction/Energy Efficiency	3.6	10.6	2 years
Capacity Costs - Indiana	0.4	7.5	1 year
Unrealized Loss on Forward Commitments	0.1	3.2	2 years
PJM Expense - Indiana	—	4.1	
Storm Related Costs - Indiana	—	1.8	
Other Regulatory Assets Approved for Recovery	0.6	1.1	various
Total Regulatory Assets Approved for Recovery	851.9	745.0	
Total Noncurrent Regulatory Assets	$ 916.6	$ 804.3	

(a) Includes $74 million and $69 million as of December 31, 2016 and 2015, respectively, expected to be recovered in formula rates.

Regulatory Liabilities:	I&M December 31, 2016	I&M December 31, 2015	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	$ —	$ 0.3	
Total Current Regulatory Liabilities	$ —	$ 0.3	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs (a)	$ 236.5	$ 350.6	(b)
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	731.2	636.5	(c)
Spent Nuclear Fuel	44.2	43.4	(c)
Deferred Investment Tax Credits	38.8	35.0	20 years
Deferred Cook Plant Life Cycle Management Project Costs - Indiana	4.6	—	3 years
PJM Expense - Indiana	4.2	—	2 years
Unrealized Gain on Forward Commitments	2.4	7.1	2 years
Rockport Plant Dry Sorbent Injection	1.7	0.4	2 years
Storm Related Costs - Indiana	1.2	—	1 year
River Transportation Division Expenses	—	1.9	
Other Regulatory Liabilities Approved for Payment	0.7	1.3	various
Total Regulatory Liabilities Approved for Payment	1,065.5	1,076.2	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,065.5	$ 1,076.2	

(a) As of December 31, 2016, I&M has charged $43 million to asset removal costs related to various Tanners Creek Plant related assets, primarily related to the net book value of ARO assets. The Indiana and Michigan retail jurisdictions of I&M have increased depreciation rates on Rockport Plant to recover the net book value of Tanners Creek Plant that was retired in 2015. I&M intends to address the need for increases in depreciation rates to recover the deferral in its next Indiana and Michigan base rate cases.

(b) Relieved as removal costs are incurred.

(c) Relieved when plant is decommissioned.

Regulatory Assets:	OPCo December 31, 2016	OPCo December 31, 2015	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Capacity Deferral	$ 96.7	$ —	
Regulatory Assets Currently Not Earning a Return			
gridSMART® Costs	4.1	1.3	
Total Regulatory Assets Pending Final Regulatory Approval	100.8	1.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Phase-In Recovery Rider	218.9	304.5	2 years
Capacity Deferral	201.9	358.7	2 years
Distribution Decoupling	41.8	37.5	2 years
Basic Transmission Cost Rider	19.9	—	2 years
RTO Formation/Integration Costs	2.5	3.1	3 years
Economic Development Rider	1.7	—	2 years
Transmission Cost Recovery Rider	—	12.3	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	225.2	219.4	12 years
Income Taxes, Net (a)	126.4	129.0	28 years
Unrealized Loss on Forward Commitments	118.6	—	16 years
OVEC Purchased Power	22.1	—	2 years
Unamortized Loss on Reacquired Debt	9.1	10.4	22 years
Medicare Subsidy	8.3	9.3	8 years
Postemployment Benefits	6.8	7.3	5 years
Distribution Investment Rider	2.0	12.3	2 years
Partnership with Ohio Contribution	1.4	2.4	2 years
gridSMART® Costs	—	4.5	
Other Regulatory Assets Approved for Recovery	0.1	1.0	various
Total Regulatory Assets Approved for Recovery	1,006.7	1,111.7	
Total Noncurrent Regulatory Assets	$ 1,107.5	$ 1,113.0	

(a) Includes $76 million and $82 million as of December 31, 2016 and 2015, respectively, expected to be recovered in formula rates.

Regulatory Liabilities:	OPCo December 31, 2016	2015	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - does not pay a return	$ 4.2	$ 27.6	1 year
Total Current Regulatory Liabilities	$ 4.2	$ 27.6	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Provision for Regulatory Loss	$ —	$ 40.6	
Other Regulatory Liabilities Pending Final Regulatory Determination	0.2	0.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	0.2	40.8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	432.4	422.3	(a)
Basic Transmission Cost Rider	0.3	4.9	2 years
Economic Development Rider	—	5.0	
Regulatory Liabilities Currently Not Paying a Return			
Peak Demand Reduction/Energy Efficiency	29.0	1.5	2 years
Enhanced Service Reliability Plan	21.7	8.0	2 years
gridSMART® Costs	11.9	—	2 years
Storm Related Costs	5.3	1.3	2 years
Deferred Asset Phase-In Rider	4.5	5.1	4 years
Unrealized Gain on Forward Commitments	—	15.3	
Regulatory Settlement	—	9.0	
Other Regulatory Liabilities Approved for Payment	0.9	1.0	various
Total Regulatory Liabilities Approved for Payment	506.0	473.4	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 506.2	$ 514.2	

(a) Relieved as removal costs are incurred.

Regulatory Assets:	PSO December 31, 2016	2015	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 33.8	$ —	1 year
Total Current Regulatory Assets	$ 33.8	$ —	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 84.5	$ —	
Other Regulatory Assets Pending Final Regulatory Approval	0.5	—	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	20.0	12.3	
Environmental Control Projects	13.1	—	
Other Regulatory Assets Pending Final Regulatory Approval	—	1.1	
Total Regulatory Assets Pending Final Regulatory Approval	118.1	13.4	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Meter Replacement Costs	50.1	35.8	8 years
Storm Related Costs	10.8	—	3 years
Red Rock Generating Facility	9.1	9.3	40 years
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	98.1	95.1	12 years
Deferred System Reliability Rider Expenses	12.5	9.9	1 year
Storm Related Costs	—	15.4	
SPP Base Plan Fees	10.7	—	2 years
Peak Demand Reduction/Energy Efficiency	10.3	11.8	2 years
Income Taxes, Net	9.3	6.1	33 years
Unamortized Loss on Reacquired Debt	5.8	6.8	16 years
Medicare Subsidy	3.9	4.4	8 years
Rate Case Expenses	1.4	1.2	1 year
Vegetation Management	—	4.5	
Other Regulatory Assets Approved for Recovery	0.1	1.1	various
Total Regulatory Assets Approved for Recovery	222.1	201.4	
Total Noncurrent Regulatory Assets	$ 340.2	$ 214.8	

Regulatory Liabilities:	PSO December 31, 2016	PSO December 31, 2015	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	$ —	$ 76.1	
Total Current Regulatory Liabilities	$ —	$ 76.1	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 279.3	$ 275.5	(a)
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	48.0	46.3	38 years
Advanced Metering Costs	11.5	11.4	1 year
Base Plan Funding Costs	—	1.3	
Other Regulatory Liabilities Approved for Payment	0.9	0.6	various
Total Regulatory Liabilities Approved for Payment	339.7	335.1	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 339.7	$ 335.1	

(a) Relieved as removal costs are incurred.

Regulatory Assets:	SWEPCo December 31, 2016	SWEPCo December 31, 2015	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 8.4	$ 4.1	1 year
Total Current Regulatory Assets	$ 8.4	$ 4.1	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 75.4	$ —	
Other Regulatory Assets Pending Final Regulatory Approval	0.8	—	
Regulatory Assets Currently Not Earning a Return			
Environmental Controls Projects	11.0	—	
Shipe Road Transmission Project - FERC	3.1	3.1	
Asset Retirement Obligation - Arkansas, Louisiana	2.7	1.7	
Rate Case Expense - Texas	1.0	0.3	
Other Regulatory Assets Pending Final Regulatory Approval	1.9	0.8	
Total Regulatory Assets Pending Final Regulatory Approval	95.9	5.9	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Approved for Recovery	1.3	0.2	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	314.2	271.9	34 years
Pension and OPEB Funded Status	119.8	108.9	12 years
Unamortized Loss on Reacquired Debt	5.4	6.0	27 years
Medicare Subsidy	4.3	4.8	8 years
Rate Case Expense - Texas	4.2	6.8	2 years
Peak Demand Reduction/Energy Efficiency	3.0	1.0	2 years
Deferred Restructuring Costs - Louisiana	1.9	3.5	2 years
Unrealized Loss on Forward Commitments	0.3	5.5	1 year
Other Regulatory Assets Approved for Recovery	0.9	1.3	various
Total Regulatory Assets Approved for Recovery	455.3	409.9	
Total Noncurrent Regulatory Assets	$ 551.2	$ 415.8	

	SWEPCo		
	December 31,		Remaining Refund Period
Regulatory Liabilities:	**2016**	**2015**	
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	$ 3.8	$ 8.4	1 year
Total Current Regulatory Liabilities	$ 3.8	$ 8.4	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 409.7	$ 396.8	(a)
Refundable Construction Financing Costs - Louisiana	16.2	37.4	2 years
Excess Earnings - Texas	2.7	2.7	37 years
Generation Recovery Rider Costs - Arkansas	1.2	1.5	2 years
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	7.3	8.5	14 years
Other Regulatory Liabilities Approved for Payment	1.8	1.9	various
Total Regulatory Liabilities Approved for Payment	438.9	448.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 438.9	$ 448.8	

(a) Relieved as removal costs are incurred.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Registrants business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against the Registrants cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, AEP subsidiaries contractually commit to third-party construction vendors for certain material purchases and other construction services. Fuel, materials, supplies, services and property, plant and equipment are also purchased under contract as part of the normal course of business. Certain supply contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following tables summarize the Registrants' actual contractual commitments as of December 31, 2016:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a) (b)	$ 1,407.8	$ 1,441.6	$ 985.5	$ 371.8	$ 4,206.7
Energy and Capacity Purchase Contracts	215.5	437.1	439.1	1,740.2	2,831.9
Total	$ 1,623.3	$ 1,878.7	$ 1,424.6	$ 2,112.0	$ 7,038.6

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 491.5	$ 433.8	$ 415.0	$ 1.2	$ 1,341.5
Energy and Capacity Purchase Contracts	33.4	68.9	72.4	430.7	605.4
Total	$ 524.9	$ 502.7	$ 487.4	$ 431.9	$ 1,946.9

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 292.7	$ 277.8	$ 221.9	$ 266.1	$ 1,058.5
Energy and Capacity Purchase Contracts	118.5	247.7	249.5	497.5	1,113.2
Total	$ 411.2	$ 525.5	$ 471.4	$ 763.6	$ 2,171.7

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 27.1	$ 55.9	$ 58.6	$ 442.6	$ 584.2
Total	$ 27.1	$ 55.9	$ 58.6	$ 442.6	$ 584.2

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 63.9	$ 55.5	$ 29.8	$ 14.9	$ 164.1
Energy and Capacity Purchase Contracts	90.6	181.7	179.9	282.3	734.5
Total	$ 154.5	$ 237.2	$ 209.7	$ 297.2	$ 898.6

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 98.4	$ 139.7	$ 69.7	$ 22.6	$ 330.4
Energy and Capacity Purchase Contracts	32.6	66.6	62.5	175.9	337.6
Total	$ 131.0	$ 206.3	$ 132.2	$ 198.5	$ 668.0

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Excludes approximately $1.1 billion of fuel purchase contracts related to plants Held for Sale. See Note 7.

GUARANTEES

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

Letters of Credit (Applies to AEP, APCo, I&M and OPCo)

Standby letters of credit are entered into with third parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

AEP has two revolving credit facilities totaling $3.5 billion. In June 2016, the $1.75 billion credit facility due in June 2017 was amended to $3 billion due in June 2021, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. Also in June 2016, the $1.75 billion credit facility due in July 2018 was amended to $500 million due in June 2018. As of December 31, 2016, no letters of credit were issued under the $3 billion revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP also issues letters of credit on behalf of subsidiaries under four uncommitted facilities totaling $300 million. As of December 31, 2016, the Registrants' maximum future payments for letters of credit issued under the uncommitted facilities were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 149.7	January 2017 to February 2018
OPCo	0.6	September 2017

The Registrants have $291 million of variable rate Pollution Control Bonds supported by $295 million of bilateral letters of credit as follows:

Company	Pollution Control Bonds	Bilateral Letters of Credit	Maturity of Bilateral Letters of Credit
	(in millions)		
AEP	$ 291.4	$ 294.7	March 2017 to July 2017
APCo	104.4	105.6	March 2017
I&M	77.0	77.9	March 2017

Guarantees of Third-Party Obligations (Applies to AEP and SWEPCo)

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, it is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of December 31, 2016, SWEPCo has collected approximately $69 million through a rider for final mine closure and reclamation costs, of which $73 million is recorded in Asset Retirement Obligations, offset by $4 million that is recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheet.

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

Guarantees of Equity Method Investees (Applies to AEP)

AEP issued a performance guarantee for a 50% owned joint venture which is accounted for as an equity method investment. If the joint venture were to default on payments or performance, AEP would be required to make payments on behalf of the joint venture. As of December 31, 2016, the maximum potential amount of future payments associated with this guarantee was $75 million, which expires in December 2019.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2016, there were no material liabilities recorded for any indemnifications.

APCo, I&M and OPCo are jointly and severally liable for activity conducted by AEPSC on behalf of AEP companies related to power purchase and sale activity. PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of PSO and SWEPCo related to power purchase and sale activity.

Lease Obligations

Certain Registrants lease certain equipment under master lease agreements. See "Master Lease Agreements", "Railcar Lease" and "AEPRO Boat and Barge Leases" sections of Note 13 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

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

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

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2016, APCo and OPCo are named as a Potentially Responsible Party (PRP) for one site and three sites, respectively, by the Federal EPA for which alleged liability is unresolved. There are nine additional sites for which APCo, I&M, OPCo and SWEPCo received information requests which could lead to PRP designation. I&M has also been named potentially liable at two sites under state law including the I&M site discussed in the next paragraph. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. In 2014, I&M recorded an accrual for remediation at certain additional sites in Michigan. As a result of receiving approval of completed remediation work from the MDEQ in March 2015, I&M's accrual was reduced. As of December 31, 2016, I&M's accrual for all of these sites is $7 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the sites or changes in the scope of remediation. Management cannot predict the amount of additional cost, if any.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for identified Superfund sites, except the I&M sites discussed above.

NUCLEAR CONTINGENCIES (APPLIES TO AEP AND I&M)

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

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2015. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste is $1.6 billion in 2015 nondiscounted dollars, with additional ongoing costs of $5 million per year for post decommissioning storage of SNF and an eventual cost of $57 million for the subsequent decommissioning of the spent fuel storage facility, also in 2015 nondiscounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $9 million, $9 million and $9 million for the years ended December 31, 2016, 2015 and 2014, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2016 and 2015, the total decommissioning trust fund balance was $1.9 billion and $1.8 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the Department of Energy (DOE) through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to zero. As of December 31, 2016 and 2015, fees and related interest of $266 million and $266 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $311 million and $309 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $6 million, $13 million and $22 million in 2016, 2015 and 2014, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2016. In February 2017, the settlement agreement was extended through December 31, 2019. The proceeds reduced costs for dry cask storage. As of December 31, 2016, I&M has deferred $22 million in Prepayments and Other Current Assets and $5 million in Deferred Charges and Other Noncurrent Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

See “Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal” section of Note 11 for disclosure of the fair value of assets within the trusts.

Nuclear Insurance

I&M carries insurance coverage in the amount of $3 billion for a nuclear incident at the Cook Plant for decontamination, stabilization and extraordinary incidents caused by premature decommissioning. Insurance coverage for a nonnuclear property incident at the Cook Plant is $1.5 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $50 million for I&M, which is assessable if the insurer’s financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident at $13.4 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $127 million on each licensed reactor in the U.S. payable in annual installments of $19 million. As a result, I&M could be assessed $255 million per nuclear incident payable in annual installments of $38 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M was initially covered for public nuclear liability for the first $375 million through commercially available insurance. Beginning in January 2017, the coverage increases to $450 million. The next level of liability coverage of up to $13 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

The Registrants maintain insurance coverage normal and customary for electric utilities, subject to various deductibles. The Registrants also maintain property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by the Registrants. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See “Nuclear Contingencies” section of this footnote for a discussion of I&M’s nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation (Applies to AEP and I&M)

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio. In October 2013, a motion to dismiss the case was filed on behalf of AEGCo and I&M. In January 2015, the court issued an opinion and order granting the motion in part and denying the motion in part. The court dismissed certain of the plaintiff's claims. Several claims remained, including the claim for breach of the participation agreement and a claim alleging breach of an implied covenant of good faith and fair dealing. In June 2015, AEGCo and I&M filed a motion for partial judgment on the claims seeking dismissal of the breach of participation agreement claim as well as any claim for indemnification of costs associated with this case. The plaintiff subsequently filed an amended complaint to add another claim under the lease and also filed a motion for partial summary judgment. In November 2015, AEGCo and I&M filed a motion to strike the plaintiff's motion for partial judgment and filed a motion to dismiss the case for failure to state a claim. In March 2016, the court entered an opinion and order in favor of AEGCo and I&M, dismissing certain of the plaintiffs' claims for breach of contract and dismissing claims for breach of implied covenant of good faith and fair dealing, and further dismissing plaintiffs' claim for indemnification of costs. By the same order, the court permitted plaintiffs to move forward with their claim that AEGCo and I&M failed to exercise prudent utility practices in the maintenance and operation of Rockport Plant, Unit 2. In April 2016, the plaintiffs filed a notice of voluntary dismissal of all remaining claims with prejudice and the court subsequently entered a final judgment. In May 2016, Plaintiffs filed a notice of appeal 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. This matter is currently pending before the U.S. Court of Appeals for the Sixth Circuit. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Natural Gas Markets Lawsuits (Applies to AEP)

In 2002, a lawsuit was commenced in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP is among the companies named as defendants in some of these cases. AEP settled, received summary judgment or was dismissed from all of these cases. The plaintiffs appealed the Nevada federal district court's dismissal of several cases involving AEP companies to the U.S. Court of Appeals for the Ninth Circuit. In April 2013, the appellate court reversed in part, and affirmed in part, the district court's orders in these cases. The United States Supreme Court affirmed the U.S. Court of Appeals for the Ninth Circuit's opinion. The cases were remanded to the district court for further proceedings. AEP had four pending cases, of which three are class actions and one is a single plaintiff case. A settlement has been reached in the three class actions and the district court issued preliminary approval of that settlement on January 26, 2017. In May 2016, the district court dismissed the remaining case. In December 2016, the plaintiff appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit. In February 2017, a tentative settlement was reached for the remaining case, subject to final documentation. Management does not expect the settlement to have a material impact on the financial statements.

Gavin Landfill Litigation (Applies to AEP and OPCo)

In August 2014, a complaint was filed in the Mason County, West Virginia Circuit Court against AEP, AEPSC, OPCo and an individual supervisor alleging wrongful death and personal injury/illness claims arising out of purported exposure to coal combustion by-product waste at the Gavin Plant landfill. As a result of OPCo transferring its generation assets to AGR, the outcome of this complaint will be the responsibility of AGR. The lawsuit was filed on behalf of 77 plaintiffs, consisting of 39 current and former contractors of the landfill and 38 family members of those contractors. Twelve of the family members are pursuing personal injury/illness claims (non-working direct claims) and the remainder are pursuing loss of consortium claims. The plaintiffs seek compensatory and punitive damages, as well as medical monitoring. In September 2014, defendants filed a motion to dismiss the complaint, contending the case should be filed in Ohio. In August 2015, the court denied the motion. Defendants appealed that decision to the West Virginia Supreme Court. In February 2016, a decision was issued by the court denying the appeal and remanding the case to the West Virginia Mass Litigation Panel (WVMLP), rather than back to the Mason County, West Virginia Circuit Court. Defendants' subsequently filed a motion to dismiss the twelve non-working direct claims under Ohio law. The WVMLP denied the motion and defendants again appealed to the West Virginia Supreme Court. The West Virginia Supreme Court granted the appeal of the twelve non-working direct claims and stayed the entire case pending oral argument in March 2017. Management will continue to defend against the claims and believes the provision recorded is adequate. Management is unable to determine a range of potential additional losses that are reasonably possible of occurring.

7. DISPOSITIONS, ASSETS AND LIABILITIES HELD FOR SALE AND IMPAIRMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

DISPOSITIONS

2016

Tanners Creek Plant (Vertically Integrated Utilities Segment) (Applies to AEP and I&M)

In October 2016, I&M sold its retired Tanners Creek Plant site including its associated asset retirement obligations (AROs) to a nonaffiliated party. I&M paid $92 million and the nonaffiliated party took ownership of the Tanners Creek plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. I&M did not record a gain or loss related to this sale and will address recovery of Tanners Creek deferred costs in future rate proceedings. If any of the costs associated with Tanners Creek are not recoverable, it could reduce future net income and impact financial condition.

2015

Muskingum River Plant (Generation & Marketing Segment)

In August 2015, AGR sold its retired Muskingum River Plant site including its associated asset retirement obligations to a nonaffiliated party. AGR paid $48 million and the nonaffiliated party took ownership of the Muskingum River Plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. As a result of the sale, a net gain of $32 million was recognized and recorded in Other Operation on the statements of income. The cash paid was recorded in Operating Activities on the statements of cash flows.

AEPRO (Corporate and Other)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. The nonaffiliated party acquired AEPRO by purchasing all of the common stock of AEP Resources, Inc., the parent company of AEPRO. The nonaffiliated party assumed certain assets and liabilities of AEPRO, excluding the equity method investment in International Marine Terminals, LLC, pension and benefit assets and liabilities and debt obligations. Prior to the closing of the sale, AEP retired the debt obligations of AEPRO. AEP retained ownership of its captive barge fleet that delivers coal to the company's regulated coal-fueled power plant units owned or leased by AEGCo, APCo, I&M, KPCo and WPCo. AEP signed a contract with the nonaffiliated party to dispatch and schedule its captive barge fleet for the company's regulated coal-fueled power plant units. AEP also had a separate contract with the nonaffiliated party to barge coal for AGR. These agreements with the nonaffiliated party extend through the end of 2019.

Results of operations of AEPRO have been classified as discontinued operations on AEP's statements of income for the years ended December 31, 2015 and 2014, as shown in the following table:

	Years Ended December 31, 2015	2014
	(in millions)	
Other Revenues	$ 447.1	$ 641.6
Other Operation Expense	321.3	459.5
Maintenance Expense	21.5	32.6
Depreciation and Amortization Expense	26.9	31.5
Taxes Other Than Income Taxes	10.6	14.2
Total Expenses	380.3	537.8
Other Income (Expense)	(16.9)	(17.1)
Pretax Income of Discontinued Operations	49.9	86.7
Income Tax Expense	19.4	39.0
Equity Earnings of Unconsolidated Subsidiaries	(0.1)	(0.2)
Income from Discontinued Operations of AEPRO	30.4	47.5
Gain on Sale of Discontinued Operations	240.1	—
Income Tax Expense (Benefit)	(13.2)	—
Gain on Sale of Discontinued Operations, Net of Tax	253.3	—
Total Income on Discontinued Operations as Presented on the Statements of Income	$ 283.7	$ 47.5

In the second quarter of 2016, AEP recorded a $3 million loss related to the final accounting for the sale of AEPRO, which was recorded in Income (Loss) from Discontinued Operations, Net of Tax, on AEP's statements of income.

ASSETS AND LIABILITIES HELD FOR SALE

2016

Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)

In September 2016, AEP signed a Purchase and Sale Agreement to sell AGR's Gavin, Waterford and Darby plants as well as AEGCo's Lawrenceburg plant totaling 5,329 MWs of competitive generation assets for approximately $2.2 billion to a nonaffiliated party. The sale closed in January 2017.

In the third quarter of 2016, management determined the disposal group met the classification of held for sale. Accordingly, the four plants' assets and liabilities have been recorded as Assets Held for Sale and Liabilities Held for Sale on AEP's balance sheet as of December 31, 2016 and as shown in the table below. The Income from Continuing Operations before Income Tax Expense (Credit) and Equity Earnings of the four plants was approximately $375 million, $451 million and $444 million for the years ended December 31, 2016, 2015 and 2014, respectively.

	December 31, 2016
	(in millions)
Assets:	
Fuel	$ 145.5
Materials and Supplies	49.4
Property, Plant and Equipment - Net	1,756.2
Other Class of Assets That Are Not Major	0.1
Total Assets Classified as Held for Sale on the Balance Sheets	$ 1,951.2
Liabilities:	
Long-term Debt	$ 134.8
Waterford Plant Upgrade Liability	52.2
Asset Retirement Obligations	36.7
Other Classes of Liabilities That Are Not Major	12.2
Total Liabilities Classified as Held for Sale on the Balance Sheets	$ 235.9

IMPAIRMENTS

2016

Merchant Generating Assets (Generation & Marketing Segment)

In September 2016, due to AEP's ongoing evaluation of strategic alternatives for its merchant generation assets, declining forecasts of future energy and capacity prices, and a decreasing likelihood of cost recovery through regulatory proceedings or legislation in the state of Ohio providing for the recovery of AEP's existing Ohio merchant generation assets, AEP performed an impairment analysis at the unit level on the remaining merchant generation assets in accordance with accounting guidance for impairments of long-lived assets. Cardinal, Unit 1, a 43.5% interest in Conesville, Unit 4, Conesville, Units 5 and 6, a 26% interest in Stuart, Units 1-4, a 25.4% interest in Zimmer, Unit 1, and a 54.7% interest in Oklaunion (collectively the "Merchant Coal-Fired Generation Assets") were subject to this analysis. Additionally, Racine Hydroelectric Plant ("Racine"), Putnam and I&M's Price River coal reserves ("Coal Reserves") and Desert Sky and Trent Wind Farms ("Wind Farms") were also included in this analysis. For the Merchant Coal-Fired Generation Assets, Racine and the Wind Farms, AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful lives of the assets based upon energy and capacity price curves, as applicable, which were developed internally with both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step one analysis concluded the book value of Racine would be recovered and the book value of the remaining assets would not be recovered.

AEP performed step two of the impairment analysis on the Merchant Coal-Fired Generation Assets using a ten-year discounted cash flow model based upon forecasted energy and capacity price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step two analysis resulted in projected negative cash flows. Based on this result, coupled with the significant capital investments necessary to comply with environmental rules to allow the Merchant Coal-Fired Generation Assets to operate to the end of their currently estimated depreciable lives and the joint-ownership structure of these facilities, management determined the fair value of these assets was $0. AEP performed step two of the impairment analysis on the Wind Farms using a ten-year discounted cash flow model utilizing forecasted energy price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The results concluded the Wind Farms were also impaired.

For the Coal Reserves, AEP performed step one of the impairment analysis and concluded the book value of the assets would not be recovered. Step two of the impairment analysis on the Coal Reserves was performed using a market approach with Level 3 unobservable inputs. The results concluded the Coal Reserves were also impaired.

Based on the impairment analysis performed, in the third quarter of 2016, AEP recorded a pretax impairment of $2.3 billion in Asset Impairments and Other Related Charges on the statements of income. See the table below for additional information.

Impaired Assets	Book Value		Fair Value		Impairment	
			(in millions)			
Merchant Coal-Fired Generation Assets	$	2,139.4	$	—	$	2,139.4
Trent and Desert Sky Wind Farms		118.7		46.0		72.7
Coal Reserves (a)		56.6		3.8		52.8
Total	$	2,314.7	$	49.8	$	2,264.9

(a) Includes the $11 million book value of I&M's Price River Coal Reserves which were fully impaired. This $11 million impairment is reflected in the Vertically Integrated Utilities Segment.

Based on capital expenditure activity of the Merchant Coal-fired Generation Assets in the fourth quarter of 2016, AEP recorded a pretax impairment of an additional $3 million in Asset Impairments and Other Related Charges on AEP's statements of income.

8. BENEFIT PLANS

The disclosures in this note apply to all Registrants unless indicated otherwise.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees.

Due to the Registrant Subsidiaries' participation in AEP's benefits plans, the assumptions used by the actuary and the accounting for the plans by each subsidiary are the same. This section details the assumptions that apply to all Registrants and the rate of compensation increase for each Registrant.

The Registrants recognize the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. The Registrants recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. The Registrants record a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of the Registrants' benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
Assumption	2016	2015	2016	2015
Discount Rate	4.05%	4.30%	4.10%	4.30%

	Pension Plans	
	December 31,	
Assumption – Rate of Compensation Increase (a)	2016	2015
AEP	4.75%	4.80%
APCo	4.55%	4.45%
I&M	4.80%	4.75%
OPCo	4.85%	4.85%
PSO	4.90%	4.85%
SWEPCo	4.75%	4.80%

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate is the same for each Registrant.

For 2016, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 12% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrants' population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of each Registrants' benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	January 1,					
Assumptions	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Discount Rate	4.30%	4.00%	4.70%	4.30%	4.00%	4.70%
Expected Return on Plan Assets	6.00%	6.00%	6.00%	7.00%	6.75%	6.75%

	Pension Plans		
	January 1,		
Assumption – Rate of Compensation Increase (a)	**2016**	**2015**	**2014**
AEP	4.75%	4.80%	4.85%
APCo	4.55%	4.45%	4.60%
I&M	4.80%	4.80%	4.90%
OPCo	4.85%	4.80%	5.00%
PSO	4.90%	4.80%	4.90%
SWEPCo	4.75%	4.80%	4.85%

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third party forecasts and current prospects for economic growth. The expected return on plan assets is the same for each Registrant.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

	January 1,	
Health Care Trend Rates	**2016**	**2015**
Initial	7.00%	6.25%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2024	2020

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost:						
1% Increase	$ 3.1	$ 0.6	$ 0.3	$ 0.2	$ 0.1	$ 0.1
1% Decrease	(2.3)	(0.5)	(0.2)	(0.2)	(0.1)	(0.1)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation:						
1% Increase	$ 58.8	$ 12.6	$ 5.6	$ 5.5	$ 2.6	$ 2.9
1% Decrease	(50.7)	(10.6)	(4.9)	(4.8)	(2.3)	(2.6)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2016, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

AEP

	Pension Plans		Other Postretirement Benefit Plans	
	2016	2015	2016	2015
Change in Benefit Obligation		(in millions)		
Benefit Obligation as of January 1,	$ 4,992.9	$ 5,224.9	$ 1,450.6	$ 1,439.0
Service Cost	85.8	93.5	10.2	12.2
Interest Cost	211.6	205.3	60.9	56.8
Actuarial (Gain) Loss	142.7	(200.6)	17.3	37.2
Benefit Payments	(347.2)	(330.2)	(130.2)	(128.7)
Participant Contributions	—	—	37.8	33.3
Medicare Subsidy	—	—	0.8	0.8
Benefit Obligation as of December 31,	$ 5,085.8	$ 4,992.9	$ 1,447.4	$ 1,450.6
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 4,767.6	$ 4,967.5	$ 1,577.4	$ 1,693.9
Actual Gain (Loss) on Plan Assets	315.5	32.4	56.0	(34.0)
Company Contributions	91.4	97.9	4.9	12.9
Participant Contributions	—	—	37.8	33.3
Benefit Payments	(347.2)	(330.2)	(130.2)	(128.7)
Fair Value of Plan Assets as of December 31,	$ 4,827.3	$ 4,767.6	$ 1,545.9	$ 1,577.4
Funded (Underfunded) Status as of December 31,	$ (258.5)	$ (225.3)	$ 98.5	$ 126.8

APCo

Change in Benefit Obligation	Pension Plans 2016	Pension Plans 2015	Other Postretirement Benefit Plans 2016	Other Postretirement Benefit Plans 2015
	(in millions)			
Benefit Obligation as of January 1,	$ 653.4	$ 702.8	$ 262.2	$ 267.1
Service Cost	8.1	8.7	1.0	1.1
Interest Cost	27.2	26.7	10.8	10.3
Actuarial (Gain) Loss	9.2	(41.4)	(0.2)	2.5
Benefit Payments	(43.9)	(43.4)	(24.8)	(24.7)
Participant Contributions	—	—	6.4	5.7
Medicare Subsidy	—	—	0.2	0.2
Benefit Obligation as of December 31,	$ 654.0	$ 653.4	$ 255.6	$ 262.2
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 603.2	$ 642.3	$ 256.7	$ 280.6
Actual Gain (Loss) on Plan Assets	38.3	(5.7)	5.9	(7.7)
Company Contributions	8.8	10.0	2.7	2.8
Participant Contributions	—	—	6.4	5.7
Benefit Payments	(43.9)	(43.4)	(24.8)	(24.7)
Fair Value of Plan Assets as of December 31,	$ 606.4	$ 603.2	$ 246.9	$ 256.7
Underfunded Status as of December 31,	$ (47.6)	$ (50.2)	$ (8.7)	$ (5.5)

I&M

Change in Benefit Obligation	Pension Plans 2016	Pension Plans 2015	Other Postretirement Benefit Plans 2016	Other Postretirement Benefit Plans 2015
	(in millions)			
Benefit Obligation as of January 1,	$ 591.5	$ 617.9	$ 166.3	$ 161.7
Service Cost	12.2	12.9	1.5	1.6
Interest Cost	25.3	24.5	7.0	6.4
Actuarial (Gain) Loss	20.1	(28.4)	3.8	7.7
Benefit Payments	(37.5)	(35.4)	(15.7)	(15.2)
Participant Contributions	—	—	4.6	4.0
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 611.6	$ 591.5	$ 167.6	$ 166.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 570.0	$ 591.7	$ 189.0	$ 202.4
Actual Gain (Loss) on Plan Assets	40.6	(0.9)	8.7	(2.3)
Company Contributions	13.0	14.6	—	0.1
Participant Contributions	—	—	4.6	4.0
Benefit Payments	(37.5)	(35.4)	(15.7)	(15.2)
Fair Value of Plan Assets as of December 31,	$ 586.1	$ 570.0	$ 186.6	$ 189.0
Funded (Underfunded) Status as of December 31,	$ (25.5)	$ (21.5)	$ 19.0	$ 22.7

OPCo

Change in Benefit Obligation	Pension Plans 2016	Pension Plans 2015	Other Postretirement Benefit Plans 2016	Other Postretirement Benefit Plans 2015
	(in millions)			
Benefit Obligation as of January 1,	$ 497.5	$ 526.3	$ 168.6	$ 164.7
Service Cost	6.5	6.7	0.8	0.9
Interest Cost	20.6	20.3	7.0	6.4
Actuarial (Gain) Loss	4.7	(19.5)	(1.0)	8.7
Benefit Payments	(36.4)	(36.3)	(16.2)	(16.3)
Participant Contributions	—	—	4.7	4.3
Medicare Subsidy	—	—	0.1	(0.1)
Benefit Obligation as of December 31,	$ 492.9	$ 497.5	$ 164.0	$ 168.6
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 472.1	$ 498.5	$ 191.6	$ 206.2
Actual Gain (Loss) on Plan Assets	30.9	2.2	2.5	(2.6)
Company Contributions	7.2	7.7	—	—
Participant Contributions	—	—	4.7	4.3
Benefit Payments	(36.4)	(36.3)	(16.2)	(16.3)
Fair Value of Plan Assets as of December 31,	$ 473.8	$ 472.1	$ 182.6	$ 191.6
Funded (Underfunded) Status as of December 31,	$ (19.1)	$ (25.4)	$ 18.6	$ 23.0

PSO

Change in Benefit Obligation	Pension Plans 2016	Pension Plans 2015	Other Postretirement Benefit Plans 2016	Other Postretirement Benefit Plans 2015
	(in millions)			
Benefit Obligation as of January 1,	$ 265.4	$ 285.4	$ 77.7	$ 76.7
Service Cost	6.2	6.4	0.6	0.7
Interest Cost	11.2	10.9	3.3	3.0
Actuarial (Gain) Loss	3.1	(17.9)	1.0	2.4
Benefit Payments	(19.2)	(19.4)	(7.2)	(7.1)
Participant Contributions	—	—	2.2	1.9
Medicare Subsidy	—	—	—	0.1
Benefit Obligation as of December 31,	$ 266.7	$ 265.4	$ 77.6	$ 77.7
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 262.1	$ 275.5	$ 88.3	$ 96.0
Actual Gain (Loss) on Plan Assets	17.3	0.1	3.1	(2.5)
Company Contributions	5.8	5.9	—	—
Participant Contributions	—	—	2.2	1.9
Benefit Payments	(19.2)	(19.4)	(7.2)	(7.1)
Fair Value of Plan Assets as of December 31,	$ 266.0	$ 262.1	$ 86.4	$ 88.3
Funded (Underfunded) Status as of December 31,	$ (0.7)	$ (3.3)	$ 8.8	$ 10.6

SWEPCo

Change in Benefit Obligation	Pension Plans 2016	Pension Plans 2015	Other Postretirement Benefit Plans 2016	Other Postretirement Benefit Plans 2015
	(in millions)			
Benefit Obligation as of January 1,	$ 282.8	$ 298.2	$ 86.1	$ 85.0
Service Cost	8.1	8.3	0.8	0.8
Interest Cost	12.4	11.8	3.6	3.4
Actuarial (Gain) Loss	13.8	(16.2)	1.5	2.1
Benefit Payments	(20.5)	(19.3)	(7.5)	(7.4)
Participant Contributions	—	—	2.4	2.1
Medicare Subsidy	—	—	—	0.1
Benefit Obligation as of December 31,	$ 296.6	$ 282.8	$ 86.9	$ 86.1

Change in Fair Value of Plan Assets	Pension Plans 2016	Pension Plans 2015	Other Postretirement Benefit Plans 2016	Other Postretirement Benefit Plans 2015
Fair Value of Plan Assets as of January 1,	$ 280.6	$ 290.2	$ 97.8	$ 106.4
Actual Gain (Loss) on Plan Assets	18.8	1.6	4.1	(3.3)
Company Contributions	8.4	8.1	—	—
Participant Contributions	—	—	2.4	2.1
Benefit Payments	(20.5)	(19.3)	(7.5)	(7.4)
Fair Value of Plan Assets as of December 31,	$ 287.3	$ 280.6	$ 96.8	$ 97.8
Funded (Underfunded) Status as of December 31,	$ (9.3)	$ (2.2)	$ 9.9	$ 11.7

Amounts Recognized on the Balance Sheets

AEP	Pension Plans 2016	Pension Plans 2015	Other Postretirement Benefit Plans 2016	Other Postretirement Benefit Plans 2015
	December 31, (in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 154.5	$ 185.8
Other Current Liabilities – Accrued Short-term Benefit Liability	(5.9)	(6.3)	(3.0)	(3.3)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(252.6)	(219.0)	(53.0)	(55.7)
Funded (Underfunded) Status	$ (258.5)	$ (225.3)	$ 98.5	$ 126.8

APCo	Pension Plans 2016	Pension Plans 2015	Other Postretirement Benefit Plans 2016	Other Postretirement Benefit Plans 2015
	December 31, (in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 25.2	$ 30.8
Other Current Liabilities – Accrued Short-term Benefit Liability	—	—	(2.4)	(2.6)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(47.6)	(50.2)	(31.5)	(33.7)
Underfunded Status	$ (47.6)	$ (50.2)	$ (8.7)	$ (5.5)

I&M	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 19.0	$ 22.7
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(25.5)	(21.5)	—	—
Funded (Underfunded) Status	$ (25.5)	$ (21.5)	$ 19.0	$ 22.7

OPCo	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 18.6	$ 23.0
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(19.1)	(25.4)	—	—
Funded (Underfunded) Status	$ (19.1)	$ (25.4)	$ 18.6	$ 23.0

PSO	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 1.6	$ —	$ 8.8	$ 10.6
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.2)	(0.2)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(2.1)	(3.1)	—	—
Funded (Underfunded) Status	$ (0.7)	$ (3.3)	$ 8.8	$ 10.6

SWEPCo	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 9.9	$ 11.7
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.1)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(9.2)	(2.1)	—	—
Funded (Underfunded) Status	$ (9.3)	$ (2.2)	$ 9.9	$ 11.7

Amounts Included in AOCI and Regulatory Assets

AEP	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
Components	(in millions)			
Net Actuarial Loss	$ 1,569.8	$ 1,546.1	$ 614.4	$ 577.4
Prior Service Cost (Credit)	1.0	3.3	(485.4)	(554.4)
Recorded as				
Regulatory Assets	$ 1,415.6	$ 1,385.2	$ 90.4	$ 15.1
Deferred Income Taxes	54.4	57.5	13.5	2.8
Net of Tax AOCI	100.8	106.7	25.1	5.1

APCo	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
Components	(in millions)			
Net Actuarial Loss	$ 216.2	$ 220.8	$ 92.9	$ 86.9
Prior Service Cost (Credit)	0.2	0.3	(70.5)	(80.6)
Recorded as				
Regulatory Assets	$ 213.7	$ 218.3	$ 7.7	$ (0.7)
Deferred Income Taxes	1.0	1.0	5.1	2.4
Net of Tax AOCI	1.7	1.8	9.6	4.6

I&M	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
Components	(in millions)			
Net Actuarial Loss	$ 133.2	$ 130.0	$ 81.3	$ 77.1
Prior Service Cost (Credit)	0.2	0.3	(66.3)	(75.7)
Recorded as				
Regulatory Assets	$ 128.2	$ 125.3	$ 13.7	$ 1.1
Deferred Income Taxes	1.8	1.8	0.5	0.1
Net of Tax AOCI	3.4	3.2	0.8	0.2

OPCo	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
Components	(in millions)			
Net Actuarial Loss	$ 215.4	$ 222.0	$ 58.2	$ 52.6
Prior Service Cost (Credit)	0.1	0.2	(48.5)	(55.4)
Recorded as				
Regulatory Assets	$ 215.5	$ 222.2	$ 9.7	$ (2.8)

PSO	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
Components	(in millions)			
Net Actuarial Loss	$ 91.0	$ 94.1	$ 37.3	$ 35.2
Prior Service Cost (Credit)	—	0.3	(30.2)	(34.5)
Recorded as				
Regulatory Assets	$ 91.0	$ 94.4	$ 7.1	$ 0.7

SWEPCo	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2016	2015	2016	2015
Components	(in millions)			
Net Actuarial Loss	$ 103.8	$ 97.1	$ 45.4	$ 43.3
Prior Service Cost (Credit)	0.1	0.4	(36.6)	(41.6)
Recorded as				
Regulatory Assets	$ 103.9	$ 97.5	$ 5.7	$ 1.2
Deferred Income Taxes	—	—	1.1	0.2
Net of Tax AOCI	—	—	2.0	0.3

Components of the change in amounts included in AOCI and Regulatory Assets by Registrant are as follows:

AEP	Pension Plans		Other Postretirement Benefit Plans	
	2016	2015	2016	2015
Components	(in millions)			
Actuarial Loss During the Year	$ 107.5	$ 41.8	$ 68.4	$ 176.3
Amortization of Actuarial Loss	(83.8)	(107.1)	(31.4)	(18.8)
Amortization of Prior Service Credit (Cost)	(2.3)	(2.2)	69.0	69.1
Change for the Year Ended December 31,	$ 21.4	$ (67.5)	$ 106.0	$ 226.6

APCo	Pension Plans		Other Postretirement Benefit Plans	
	2016	2015	2016	2015
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 6.2	$ (0.3)	$ 11.4	$ 24.7
Amortization of Actuarial Loss	(10.8)	(13.9)	(5.4)	(3.6)
Amortization of Prior Service Credit (Cost)	(0.1)	(0.2)	10.1	10.0
Change for the Year Ended December 31,	$ (4.7)	$ (14.4)	$ 16.1	$ 31.1

I&M	Pension Plans		Other Postretirement Benefit Plans	
	2016	2015	2016	2015
Components	(in millions)			
Actuarial Loss During the Year	$ 13.2	$ 4.7	$ 7.9	$ 24.7
Amortization of Actuarial Loss	(10.0)	(12.6)	(3.7)	(2.0)
Amortization of Prior Service Credit (Cost)	(0.1)	(0.2)	9.4	9.4
Change for the Year Ended December 31,	$ 3.1	$ (8.1)	$ 13.6	$ 32.1

OPCo	Pension Plans		Other Postretirement Benefit Plans	
	2016	2015	2016	2015
Components	(in millions)			
Actuarial Loss During the Year	$ 1.5	$ 5.8	$ 9.4	$ 24.0
Amortization of Actuarial Loss	(8.1)	(10.5)	(3.8)	(2.1)
Amortization of Prior Service Credit (Cost)	(0.1)	(0.2)	6.9	7.0
Change for the Year Ended December 31,	$ (6.7)	$ (4.9)	$ 12.5	$ 28.9

PSO	Pension Plans		Other Postretirement Benefit Plans	
	2016	2015	2016	2015
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 1.3	$ (2.9)	$ 3.9	$ 10.9
Amortization of Actuarial Loss	(4.4)	(5.7)	(1.8)	(1.0)
Amortization of Prior Service Credit (Cost)	(0.3)	(0.2)	4.3	4.3
Change for the Year Ended December 31,	$ (3.4)	$ (8.8)	$ 6.4	$ 14.2

SWEPCo	Pension Plans		Other Postretirement Benefit Plans	
	2016	2015	2016	2015
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 11.5	$ (1.8)	$ 4.0	$ 12.0
Amortization of Actuarial Loss	(4.8)	(6.0)	(1.9)	(1.1)
Amortization of Prior Service Credit (Cost)	(0.3)	(0.3)	5.0	5.2
Change for the Year Ended December 31,	$ 6.4	$ (8.1)	$ 7.1	$ 16.1

Pension and Other Postretirement Benefits Plans' Assets

The fair value tables within Pension and Other Postretirement Benefits Plans' Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to the Registrant Subsidiaries using the percentages in the table below:

	Pension Plan		Other Postretirement Benefit Plans	
	December 31,			
Company	2016	2015	2016	2015
APCo	12.6%	12.7%	16.0%	16.3%
I&M	12.1%	12.0%	12.1%	12.0%
OPCo	9.8%	9.9%	11.8%	12.1%
PSO	5.5%	5.5%	5.6%	5.6%
SWEPCo	6.0%	5.9%	6.3%	6.2%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2016:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 354.7	$ —	$ —	$ —	$ 354.7	7.3 %
International	439.2	—	—	—	439.2	9.1 %
Options	—	20.0	—	—	20.0	0.4 %
Real Estate Investment Trusts	3.1	—	—	—	3.1	0.1 %
Common Collective Trusts (c)	—	14.0	—	400.5	414.5	8.6 %
Subtotal – Equities	797.0	34.0	—	400.5	1,231.5	25.5 %
Fixed Income:						
Common Collective Trust – Debt (c)	—	—	—	32.3	32.3	0.7 %
United States Government and Agency Securities (c)	—	423.3	—	17.7	441.0	9.1 %
Corporate Debt (c)	—	1,932.2	—	10.0	1,942.2	40.2 %
Foreign Debt (c)	—	373.7	—	12.1	385.8	8.0 %
State and Local Government	—	11.5	—	—	11.5	0.2 %
Other – Asset Backed (c)	—	5.4	—	7.4	12.8	0.3 %
Subtotal – Fixed Income	—	2,746.1	—	79.5	2,825.6	58.5 %
Infrastructure	—	—	57.6	—	57.6	1.2 %
Real Estate	—	—	254.9	—	254.9	5.3 %
Alternative Investments	—	—	411.1	—	411.1	8.5 %
Securities Lending	—	161.6	—	—	161.6	3.4 %
Securities Lending Collateral (a)	—	—	—	(163.3)	(163.3)	(3.4)%
Cash and Cash Equivalents (c)	—	—	—	29.7	29.7	0.6 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	18.6	18.6	0.4 %
Total	$ 797.0	$ 2,941.7	$ 723.6	$ 365.0	$ 4,827.3	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which was retrospectively applied to prior periods.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Foreign Debt	Infrastructure	Real Estate	Alternative Investments	Total Level 3
			(in millions)		
Balance as of January 1, 2016	$ 0.1	$ 42.0	$ 253.7	$ 378.7	$ 674.5
Actual Return on Plan Assets					
Relating to Assets Still Held as of the Reporting Date	—	5.9	5.3	13.7	24.9
Relating to Assets Sold During the Period	—	0.9	23.2	21.1	45.2
Purchases and Sales	(0.1)	8.8	(27.3)	(2.4)	(21.0)
Transfers into Level 3	—	—	—	—	—
Transfers out of Level 3	—	—	—	—	—
Balance as of December 31, 2016	$ —	$ 57.6	$ 254.9	$ 411.1	$ 723.6

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2016:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 517.1	$ —	$ —	$ —	$ 517.1	33.5 %
International	435.5	—	—	—	435.5	28.2 %
Options	—	15.2	—	—	15.2	1.0 %
Common Collective Trusts (b)	—	10.9	—	20.5	31.4	2.0 %
Subtotal – Equities	952.6	26.1	—	20.5	999.2	64.7 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	93.7	93.7	6.0 %
United States Government and Agency Securities	—	64.7	—	—	64.7	4.2 %
Corporate Debt	—	121.6	—	—	121.6	7.9 %
Foreign Debt	—	18.6	—	—	18.6	1.2 %
State and Local Government	—	3.0	—	—	3.0	0.2 %
Other – Asset Backed	—	5.9	—	—	5.9	0.4 %
Subtotal – Fixed Income	—	213.8	—	93.7	307.5	19.9 %
Trust Owned Life Insurance:						
International Equities (b)	—	—	—	110.1	110.1	7.1 %
United States Bonds (b)	—	—	—	97.4	97.4	6.3 %
Subtotal – Trust Owned Life Insurance	—	—	—	207.5	207.5	13.4 %
Cash and Cash Equivalents	24.0	10.5	—	—	34.5	2.2 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(2.8)	(2.8)	(0.2)%
Total	$ 976.6	$ 250.4	$ —	$ 318.9	$ 1,545.9	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which was retrospectively applied to prior periods.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2015:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 315.7	$ —	$ —	$ —	$ 315.7	6.6 %
International	402.3	—	—	—	402.3	8.4 %
Options	—	15.6	—	—	15.6	0.3 %
Real Estate Investment Trusts	4.0	—	—	—	4.0	0.1 %
Common Collective Trusts (c)	—	16.1	—	369.7	385.8	8.1 %
Subtotal – Equities	722.0	31.7	—	369.7	1,123.4	23.5 %
Fixed Income:						
Common Collective Trust – Debt (c)	—	—	—	34.2	34.2	0.7 %
United States Government and Agency Securities (c)	—	397.8	—	24.1	421.9	8.9 %
Corporate Debt (c)	—	1,964.2	—	19.0	1,983.2	41.6 %
Foreign Debt (c)	—	405.4	0.1	16.0	421.5	8.8 %
State and Local Government	—	12.8	—	—	12.8	0.3 %
Other – Asset Backed (c)	—	15.8	—	7.6	23.4	0.5 %
Subtotal – Fixed Income	—	2,796.0	0.1	100.9	2,897.0	60.8 %
Infrastructure	—	—	42.0	—	42.0	0.9 %
Real Estate	—	—	253.7	—	253.7	5.3 %
Alternative Investments	—	—	378.7	—	378.7	8.0 %
Securities Lending	—	263.0	—	—	263.0	5.5 %
Securities Lending Collateral (a)	—	—	—	(264.7)	(264.7)	(5.5)%
Cash and Cash Equivalents (c)	—	1.2	—	47.4	48.6	1.0 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	25.9	25.9	0.5 %
Total	$ 722.0	$ 3,091.9	$ 674.5	$ 279.2	$ 4,767.6	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which was retrospectively applied to prior periods.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Foreign Debt	Infrastructure	Real Estate	Alternative Investments	Total Level 3
			(in millions)		
Balance as of January 1, 2015	$ 0.1	$ 12.5	$ 235.8	$ 378.9	$ 627.3
Actual Return on Plan Assets					
Relating to Assets Still Held as of the Reporting Date	—	(3.6)	12.5	(25.9)	(17.0)
Relating to Assets Sold During the Period	—	0.3	23.8	37.6	61.7
Purchases and Sales	—	32.8	(18.4)	(11.9)	2.5
Transfers into Level 3	—	—	—	—	—
Transfers out of Level 3	—	—	—	—	—
Balance as of December 31, 2015	$ 0.1	$ 42.0	$ 253.7	$ 378.7	$ 674.5

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2015:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 465.1	$ —	$ —	$ —	$ 465.1	29.5%
International	484.3	—	—	—	484.3	30.7%
Options	—	15.6	—	—	15.6	1.0%
Common Collective Trusts (b)	—	12.6	—	19.0	31.6	2.0%
Subtotal – Equities	949.4	28.2	—	19.0	996.6	63.2%
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	100.9	100.9	6.4%
United States Government and Agency Securities	—	58.4	—	—	58.4	3.7%
Corporate Debt	—	117.7	—	—	117.7	7.4%
Foreign Debt	—	20.7	—	—	20.7	1.3%
State and Local Government	—	4.2	—	—	4.2	0.3%
Other – Asset Backed	—	8.4	—	—	8.4	0.5%
Subtotal – Fixed Income	—	209.4	—	100.9	310.3	19.6%
Trust Owned Life Insurance:						
International Equities (b)	—	—	—	28.3	28.3	1.8%
United States Bonds (b)	—	—	—	184.3	184.3	11.7%
Subtotal – Trust Owned Life Insurance	—	—	—	212.6	212.6	13.5%
Cash and Cash Equivalents	44.9	7.2	—	—	52.1	3.3%
Other – Pending Transactions and Accrued Income (a)	—	—	—	5.8	5.8	0.4%
Total	$ 994.3	$ 244.8	$ —	$ 338.3	$ 1,577.4	100.0%

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which was retrospectively applied to prior periods.

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Qualified Pension Plan	$ 4,846.0	$ 641.0	$ 588.5	$ 478.0	$ 252.0	$ 279.8
Nonqualified Pension Plans	69.8	0.3	0.3	—	2.2	1.7
Total as of December 31, 2016	$ 4,915.8	$ 641.3	$ 588.8	$ 478.0	$ 254.2	$ 281.5

Accumulated Benefit Obligation	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Qualified Pension Plan	$ 4,757.1	$ 641.4	$ 571.3	$ 484.1	$ 252.0	$ 267.7
Nonqualified Pension Plans	75.6	0.5	0.4	0.1	2.4	1.6
Total as of December 31, 2015	$ 4,832.7	$ 641.9	$ 571.7	$ 484.2	$ 254.4	$ 269.3

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans were as follows:

	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Projected Benefit Obligation	$ 5,085.8	$ 654.0	$ 611.6	$ 492.9	$ 2.3	$ 1.7
Accumulated Benefit Obligation	$ 4,915.8	$ 641.3	$ 588.8	$ 478.0	$ 2.2	$ 1.7
Fair Value of Plan Assets	4,827.3	606.4	586.1	473.8	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2016	$ (88.5)	$ (34.9)	$ (2.7)	$ (4.2)	$ (2.2)	$ (1.7)

	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Projected Benefit Obligation	$ 4,992.9	$ 653.4	$ 591.5	$ 497.5	$ 2.6	$ 1.7
Accumulated Benefit Obligation	$ 4,832.7	$ 641.9	$ 571.7	$ 484.2	$ 2.4	$ 1.6
Fair Value of Plan Assets	4,767.6	603.2	570.0	472.1	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2015	$ (65.1)	$ (38.7)	$ (1.7)	$ (12.1)	$ (2.4)	$ (1.6)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded nonqualified benefits. For the qualified pension plan, additional discretionary contributions may also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant for 2017:

Company	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
AEP	$ 98.2	$ 4.3
APCo	10.2	2.4
I&M	13.6	—
OPCo	7.6	—
PSO	5.5	—
SWEPCo	8.7	—

The tables below reflect the total benefits expected to be paid from the plan or from the Registrants' assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

Pension Plans	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
2017	$ 332.6	$ 43.2	$ 35.7	$ 35.8	$ 19.6	$ 20.1
2018	335.6	42.9	35.9	35.7	19.3	21.3
2019	344.5	43.8	38.6	35.8	20.3	22.0
2020	351.2	44.5	38.7	36.1	20.4	22.6
2021	364.4	46.0	40.2	35.4	21.9	23.6
Years 2022 to 2026, in Total	1,841.2	231.2	216.5	172.6	106.7	122.2

Other Postretirement Benefit Plans: Benefit Payments	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
2017	$ 137.0	$ 25.4	$ 16.6	$ 17.0	$ 7.6	$ 8.0
2018	138.2	25.6	16.7	17.0	7.6	8.1
2019	138.3	25.2	16.8	17.0	7.7	8.2
2020	139.7	25.2	16.9	16.9	7.9	8.4
2021	141.1	25.1	17.2	16.9	7.9	8.7
Years 2022 to 2026, in Total	718.0	122.7	87.6	83.8	41.1	46.6

Other Postretirement Benefit Plans: Medicare Subsidy Receipts	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
2017	$ 0.3	$ 0.2	$ —	$ —	$ —	$ —
2018	0.3	0.2	—	—	—	—
2019	0.3	0.2	—	—	—	—
2020	0.3	0.2	—	—	—	—
2021	0.3	0.2	—	—	—	—
Years 2022 to 2026, in Total	1.7	1.0	—	—	—	—

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost (credit) by Registrant for the plans:

AEP	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2016	2015	2014	2016	2015	2014
			(in millions)			
Service Cost	$ 85.8	$ 93.5	$ 71.9	$ 10.2	$ 12.2	$ 14.2
Interest Cost	211.6	205.3	221.0	60.9	56.8	67.2
Expected Return on Plan Assets	(280.3)	(274.8)	(261.6)	(107.0)	(111.0)	(111.3)
Amortization of Prior Service Cost (Credit)	2.3	2.2	2.5	(69.0)	(69.1)	(69.0)
Amortization of Net Actuarial Loss	83.8	107.1	124.0	31.4	18.8	22.1
Net Periodic Benefit Cost (Credit)	103.2	133.3	157.8	(73.5)	(92.3)	(76.8)
Capitalized Portion	(37.8)	(48.4)	(52.2)	26.9	33.5	25.3
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 65.4	$ 84.9	$ 105.6	$ (46.6)	$ (58.8)	$ (51.5)

APCo

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2016	2015	2014	2016	2015	2014
	(in millions)					
Service Cost	$ 8.1	$ 8.7	$ 7.0	$ 1.0	$ 1.1	$ 1.4
Interest Cost	27.2	26.7	29.6	10.8	10.3	12.8
Expected Return on Plan Assets	(35.3)	(35.0)	(33.9)	(17.3)	(18.1)	(18.5)
Amortization of Prior Service Cost (Credit)	0.1	0.2	0.2	(10.1)	(10.0)	(10.1)
Amortization of Net Actuarial Loss	10.8	13.9	16.6	5.4	3.6	4.6
Net Periodic Benefit Cost (Credit)	10.9	14.5	19.5	(10.2)	(13.1)	(9.8)
Capitalized Portion	(4.1)	(5.5)	(6.8)	3.9	5.0	3.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 6.8	$ 9.0	$ 12.7	$ (6.3)	$ (8.1)	$ (6.4)

I&M

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2016	2015	2014	2016	2015	2014
	(in millions)					
Service Cost	$ 12.2	$ 12.9	$ 10.0	$ 1.5	$ 1.6	$ 1.9
Interest Cost	25.3	24.5	26.3	7.0	6.4	7.6
Expected Return on Plan Assets	(33.6)	(32.6)	(31.0)	(12.9)	(13.2)	(13.4)
Amortization of Prior Service Cost (Credit)	0.1	0.2	0.2	(9.4)	(9.4)	(9.4)
Amortization of Net Actuarial Loss	10.0	12.6	14.6	3.7	2.0	2.4
Net Periodic Benefit Cost (Credit)	14.0	17.6	20.1	(10.1)	(12.6)	(10.9)
Capitalized Portion	(3.3)	(4.0)	(4.6)	2.4	2.9	2.5
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 10.7	$ 13.6	$ 15.5	$ (7.7)	$ (9.7)	$ (8.4)

OPCo

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2016	2015	2014	2016	2015	2014
	(in millions)					
Service Cost	$ 6.5	$ 6.7	$ 5.2	$ 0.8	$ 0.9	$ 1.0
Interest Cost	20.6	20.3	22.1	7.0	6.4	7.6
Expected Return on Plan Assets	(27.6)	(27.5)	(26.5)	(13.0)	(13.4)	(13.5)
Amortization of Prior Service Cost (Credit)	0.1	0.2	0.2	(6.9)	(7.0)	(6.9)
Amortization of Net Actuarial Loss	8.1	10.5	12.4	3.8	2.1	2.4
Net Periodic Benefit Cost (Credit)	7.7	10.2	13.4	(8.3)	(11.0)	(9.4)
Capitalized Portion	(3.4)	(4.8)	(5.5)	3.7	5.2	3.8
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 4.3	$ 5.4	$ 7.9	$ (4.6)	$ (5.8)	$ (5.6)

PSO

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2016	2015	2014	2016	2015	2014
	(in millions)					
Service Cost	$ 6.2	$ 6.4	$ 5.2	$ 0.6	$ 0.7	$ 0.8
Interest Cost	11.2	10.9	12.1	3.3	3.0	3.6
Expected Return on Plan Assets	(15.5)	(15.1)	(14.6)	(6.1)	(6.3)	(6.3)
Amortization of Prior Service Cost (Credit)	0.3	0.2	0.3	(4.3)	(4.3)	(4.3)
Amortization of Net Actuarial Loss	4.4	5.7	6.7	1.8	1.0	1.1
Net Periodic Benefit Cost (Credit)	6.6	8.1	9.7	(4.7)	(5.9)	(5.1)
Capitalized Portion	(2.4)	(2.8)	(3.3)	1.7	2.0	1.7
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 4.2	$ 5.3	$ 6.4	$ (3.0)	$ (3.9)	$ (3.4)

SWEPCo	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2016	2015	2014	2016	2015	2014
	(in millions)					
Service Cost	$ 8.1	$ 8.3	$ 6.6	$ 0.8	$ 0.8	$ 1.0
Interest Cost	12.4	11.8	12.7	3.6	3.4	4.0
Expected Return on Plan Assets	(16.4)	(16.0)	(15.4)	(6.8)	(6.9)	(7.0)
Amortization of Prior Service Cost (Credit)	0.3	0.3	0.3	(5.0)	(5.2)	(5.2)
Amortization of Net Actuarial Loss	4.8	6.0	7.1	1.9	1.1	1.2
Net Periodic Benefit Cost (Credit)	9.2	10.4	11.3	(5.5)	(6.8)	(6.0)
Capitalized Portion	(2.7)	(3.2)	(3.4)	1.6	2.1	1.8
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 6.5	$ 7.2	$ 7.9	$ (3.9)	$ (4.7)	$ (4.2)

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on each Registrants' balance sheet during 2017 are shown in the following tables:

Pension Plans – Components	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Net Actuarial Loss	$ 84.2	$ 10.7	$ 10.0	$ 8.1	$ 4.4	$ 4.9
Prior Service Cost	1.0	0.2	0.2	0.1	—	—
Total Estimated 2017 Amortization	$ 85.2	$ 10.9	$ 10.2	$ 8.2	$ 4.4	$ 4.9
Pension Plans – Expected to be Recorded as						
Regulatory Asset	$ 74.1	$ 10.9	$ 9.6	$ 8.2	$ 4.4	$ 4.9
Deferred Income Taxes	3.9	—	0.2	—	—	—
Net of Tax AOCI	7.2	—	0.4	—	—	—
Total	$ 85.2	$ 10.9	$ 10.2	$ 8.2	$ 4.4	$ 4.9

Other Postretirement Benefit Plans – Components	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Net Actuarial Loss	$ 34.4	$ 5.8	$ 4.1	$ 4.0	$ 1.9	$ 2.2
Prior Service Credit	(69.0)	(10.0)	(9.4)	(6.9)	(4.3)	(5.2)
Total Estimated 2017 Amortization	$ (34.6)	$ (4.2)	$ (5.3)	$ (2.9)	$ (2.4)	$ (3.0)
Other Postretirement Benefit Plans – Expected to be Recorded as						
Regulatory Asset	$ (25.1)	$ (2.2)	$ (4.8)	$ (2.9)	$ (2.4)	$ (1.9)
Deferred Income Taxes	(3.3)	(0.7)	(0.2)	—	—	(0.4)
Net of Tax AOCI	(6.2)	(1.3)	(0.3)	—	—	(0.7)
Total	$ (34.6)	$ (4.2)	$ (5.3)	$ (2.9)	$ (2.4)	$ (3.0)

American Electric Power System Retirement Savings Plan

AEP sponsors the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not covered by a retirement savings plan of the United Mine Workers of America (UMWA). This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions.

The following table provides the cost for matching contributions to the retirement savings plans by Registrant:

Company	Year Ended December 31, 2016	2015	2014
		(in millions)	
AEP	$ 72.9	$ 73.6	$ 70.5
APCo	7.3	7.2	7.3
I&M	10.9	10.6	10.5
OPCo	5.6	5.4	5.2
PSO	4.3	4.2	4.0
SWEPCo	5.7	5.7	5.3

UMWA Benefits

Health and Welfare Benefits (Applies to AEP and APCo)

AEP provides health and welfare benefits for certain unionized employees, retirees and their survivors who meet eligibility requirements. APCo also provides the same UMWA health and welfare benefits for certain unionized mining retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. AEP and APCo administer the health and welfare benefits and pay them from their general assets.

Multiemployer Pension Benefits (Applies to AEP)

UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), a multiemployer plan. The UMWA pension benefits are administered by a board of trustees appointed in equal numbers by the UMWA and the Bituminous Coal Operators' Association (BCOA), an industry bargaining association. AEP makes contributions to the United Mine Workers of America 1974 Pension Plan based on provisions in its labor agreement and the plan documents. The UMWA pension plan is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. A withdrawing employer may be subject to a withdrawal liability, which is calculated based upon that employer's share of the plan's unfunded benefit obligations. If an employer fails to make required contributions or if its payments in connection with its withdrawal liability fall short of satisfying its share of the plan's unfunded benefit obligations, the remaining employers may be allocated a greater share of the remaining unfunded plan obligations. Under the Pension Protection Act of 2006 (PPA), the UMWA pension plan was in Critical and Declining Status for the plan years ending June 30, 2016 and 2015, without utilization of extended amortization provisions. As required under the PPA, the Plan adopted a Rehabilitation Plan in February 2015 which was updated in May 2016 and again in August 2016.

The amounts contributed in 2016, 2015 and 2014 were immaterial and represent less than 5% of the total contributions in the plan's latest annual report based on the plan year ended June 30, 2015. UMWA pension contributions included a surcharge of 5% from December 2014 through June 2015. UMWA pension contributions included a surcharge of 10% from July 2015 through June 2016 at which time new base contribution rates went into effect with no associated surcharges.

Under the terms of the UMWA pension plan, contributions will be required to continue beyond the December 31, 2017 expiration of the current collective bargaining agreement, whether or not the term of that agreement is extended or a subsequent agreement is entered, so long as both the UMWA pension plan remains in effect and an AEP affiliate continues to operate the facility covered by the current collective bargaining agreement. The contribution rate applicable would be determined in accordance with the terms of the UMWA pension plan by reference to the National Bituminous Coal Wage Agreement, subject to periodic revisions, between the UMWA and the BCOA. If the UMWA pension plan would terminate or an AEP affiliate would cease operation of the facility without arranging for a successor operator to assume its liability, the withdrawal liability obligation would be triggered.

Based upon the planned closure of Cook Coal Terminal in 2022, AEP records a UMWA pension withdrawal liability on the balance sheet. The UMWA pension withdrawal liability is re-measured annually and is related to the company's proportionate share of the plan's unfunded vested liabilities. As of December 31, 2016 and 2015, the liability balance was $39 million and $31 million, respectively. AEP recovers the estimated UMWA pension withdrawal liability through fuel clauses in certain regulated jurisdictions. A regulatory asset is recorded on the balance sheet when the UMWA pension withdrawal liability exceeds the cumulative billings collected. As of December 31, 2016 and 2015, the regulatory asset balance was $20 million and $14 million, respectively. If any portion of the UMWA pension withdrawal liability is not recoverable, it could reduce future net income and cash flows and impact financial condition.

9. BUSINESS SEGMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

AEP's Reportable 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 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 AEP's wholly-owned transmission-only subsidiaries and transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

- 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. With the sale of AEPRO in November 2015, the activities related to the AEP River Operations segment have been moved to Corporate and Other for the periods presented. See "AEPRO (Corporate and Other)" section of Note 7 for additional information.

The tables below present AEP's reportable segment income statement information for the years ended December 31, 2016, 2015 and 2014 and reportable segment balance sheet information as of December 31, 2016 and 2015. These amounts include certain estimates and allocations where necessary.

2016	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 9,012.4	$ 4,328.3	$ 145.9	$ 2,858.7	$ 34.8	$ —	$ 16,380.1
Other Operating Segments	79.5	94.1	366.9	127.3	70.3	(738.1)	—
Total Revenues	$ 9,091.9	$ 4,422.4	$ 512.8	$ 2,986.0	$ 105.1	$ (738.1)	$ 16,380.1
Asset Impairments and Other Related Charges	$ 10.5	$ —	$ —	$ 2,257.3	$ —	$ —	$ 2,267.8
Depreciation and Amortization	1,073.8	649.9	67.1	154.6	0.2	16.7 (d)	1,962.3
Interest and Investment Income	4.8	14.8	0.4	1.4	11.8	(16.9)	16.3
Carrying Costs Income	10.5	20.0	(0.3)	—	—	(14.0)	16.2
Interest Expense	522.1	256.9	50.3	35.8	40.5	(28.4) (d)	877.2
Income Tax Expense (Credit)	397.3	205.1	134.1	(666.5)	(143.7)	—	(73.7)
Income (Loss) from Continuing Operations	$ 984.0	$ 482.1	$ 269.3	$ (1,198.0)	$ 83.1	$ —	$ 620.5
Income (Loss) from Discontinued Operations, Net of Tax	—	—	—	—	(2.5)	—	(2.5)
Net Income (Loss)	$ 984.0	$ 482.1	$ 269.3	$ (1,198.0)	$ 80.6	$ —	$ 618.0
Gross Property Additions	$ 2,237.0	$ 1,058.3	$ 1,265.8	$ 336.2	$ 9.8	$ (18.1)	$ 4,889.0
Total Property, Plant and Equipment	$ 41,552.6	$ 14,762.2	$ 5,354.0	$ 364.7	$ 356.6	$ (353.5) (d)	$ 62,036.6
Accumulated Depreciation and Amortization	12,596.7	3,655.0	101.4	42.2	186.0	(184.0) (d)	16,397.3
Total Property, Plant and Equipment – Net	$ 28,955.9	$ 11,107.2	$ 5,252.6	$ 322.5	$ 170.6	$ (169.5) (d)	$ 45,639.3
Assets Held for Sale	$ —	$ —	$ —	$ 1,951.2	$ —	$ —	$ 1,951.2
Total Assets	$ 37,428.3	$ 14,802.4	$ 6,384.8	$ 3,386.1	$ 20,354.8	$ (18,888.7) (d) (e)	$ 63,467.7
Investments in Equity Method Investees	$ 41.2	$ 1.2	$ 742.0	$ 0.1	$ 24.9	$ —	$ 809.4
Long-term Debt Due Within One Year:							
Non-Affiliated	$ 1,519.9	$ 309.4	$ —	$ 500.1	$ 548.6	$ —	$ 2,878.0
Long-term Debt:							
Affiliated	20.0	—	—	32.2	—	(52.2)	—
Non-Affiliated	10,353.3	4,672.2	2,055.7	—	297.2	—	17,378.4
Total Long-term Debt	$ 11,893.2	$ 4,981.6	$ 2,055.7	$ 532.3	$ 845.8	$ (52.2)	$ 20,256.4
Liabilities Held for Sale	$ —	$ —	$ —	$ 235.9	$ —	$ —	$ 235.9

2015	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments		Consolidated
				(in millions)				
Revenues from:								
External Customers	$ 9,069.9	$ 4,392.0	$ 100.6	$ 2,866.7	$ 24.0	$ —		$ 16,453.2
Other Operating Segments	102.3	164.6	228.6	546.0	75.0	(1,116.5)		—
Total Revenues	$ 9,172.2	$ 4,556.6	$ 329.2	$ 3,412.7	$ 99.0	$ (1,116.5)		$ 16,453.2
Depreciation and Amortization	$ 1,062.6	$ 686.4	$ 43.0	$ 201.4	$ 0.8	$ 15.5	(d)	$ 2,009.7
Interest and Investment Income	4.6	6.4	0.2	2.8	9.2	(15.3)		7.9
Carrying Costs Income	11.8	11.8	(0.2)	—	—	0.1		23.5
Interest Expense	517.4	276.2	37.2	40.0	30.3	(27.2)	(d)	873.9
Income Tax Expense (Credit)	449.3	185.5	91.3	194.6	(1.1)	—		919.6
Income (Loss) from Continuing Operations	$ 900.2	$ 352.4	$ 192.7	$ 366.0	$ (42.7)	$ —		$ 1,768.6
Income from Discontinued Operations, Net of Tax	—	—	—	—	283.7	—		283.7
Net Income	$ 900.2	$ 352.4	$ 192.7	$ 366.0	$ 241.0	$ —		$ 2,052.3
Gross Property Additions	$ 2,222.3	$ 1,048.4	$ 1,121.3	$ 134.3	$ 4.8	$ (17.8)		$ 4,513.3
Total Property, Plant and Equipment	$ 40,130.3	$ 13,840.5	$ 3,977.6	$ 7,461.3	$ 350.9	$ (279.2)	(d)	$ 65,481.4
Accumulated Depreciation and Amortization	12,335.0	3,529.2	52.3	3,367.0	176.9	(112.2)	(d)	19,348.2
Total Property, Plant and Equipment – Net	$ 27,795.3	$ 10,311.3	$ 3,925.3	$ 4,094.3	$ 174.0	$ (167.0)	(d)	$ 46,133.2
Total Assets	$ 35,792.3	$ 14,795.0	$ 5,012.1	$ 5,414.5	$ 20,242.2	$ (19,573.0)	(d) (e)	$ 61,683.1
Investments in Equity Method Investees	$ 31.9	$ 0.9	$ 630.8	$ 0.1	$ 56.8	$ —		$ 720.5
Long-term Debt Due Within One Year:								
Non-Affiliated	$ 935.4	$ 824.7	$ —	$ 71.6	$ 0.1	$ —		$ 1,831.8
Long-term Debt:								
Affiliated	20.0	—	—	32.2	—	(52.2)		—
Non-Affiliated	9,833.0	4,776.8	1,648.4	639.5	843.2	—		17,740.9
Total Long-term Debt	$ 10,788.4	$ 5,601.5	$ 1,648.4	$ 743.3	$ 843.3	$ (52.2)		$ 19,572.7

2014	Vertically Integrated Utilities		Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing		Corporate and Other (a)	Reconciling Adjustments		Consolidated
					(in millions)					
Revenues from:										
External Customers	$ 9,396.8	(b)	$ 4,552.6	$ 73.9	$ 2,384.3	(b)	$ 22.2	$ (51.2)	(c)	$ 16,378.6
Other Operating Segments	87.6	(b)	261.0	118.0	1,465.3	(b)	73.2	(2,005.1)		—
Total Revenues	$ 9,484.4		$ 4,813.6	$ 191.9	$ 3,849.6		$ 95.4	$ (2,056.3)		$ 16,378.6
Depreciation and Amortization	$ 1,033.0		$ 657.8	$ 23.7	$ 226.8		$ —	$ (43.7)	(d)	$ 1,897.6
Interest and Investment Income	3.4		10.1	—	4.7		8.6	(19.4)		7.4
Carrying Costs Income	6.7		26.5	—	—		—	—		33.2
Interest Expense	525.5		280.3	23.5	45.3		25.1	(31.7)	(d)	868.0
Income Tax Expense	433.5		211.7	62.9	179.3		15.2	—		902.6
Income from Continuing Operations	$ 711.8		$ 352.2	$ 150.8	$ 367.4		$ 8.3	$ —		$ 1,590.5
Income from Discontinued Operations, Net of Tax	—		—	—	—		47.5	—		47.5
Net Income	$ 711.8		$ 352.2	$ 150.8	$ 367.4		$ 55.8	$ —		$ 1,638.0
Gross Property Additions	$ 2,054.7		$ 1,037.7	$ 948.3	$ 164.9		$ 17.2	$ (28.0)		$ 4,194.8
Total Assets	$ 33,705.1		$ 14,524.6	$ 3,570.0	$ 6,326.2		$ 20,512.9	$ (19,094.2)	(d) (e)	$ 59,544.6

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense and discontinued operations of AEPRO and other nonallocated costs.
(b) Includes the impact of the corporate separation of OPCo's generation assets and liabilities that took effect December 31, 2013, as well as the impact of the termination of the Interconnection Agreement effective January 1, 2014.
(c) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation in Ohio.
(d) Includes eliminations due to an intercompany capital lease.
(e) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

Registrant Subsidiaries' Reportable Segments

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business for APCo, I&M, PSO and SWEPCo, and an electricity transmission and distribution business for OPCo. The Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

10. DERIVATIVES AND HEDGING

The disclosures in this note apply to all Registrants unless indicated otherwise.

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of AEP subsidiaries, including the Registrant Subsidiaries. AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

The Registrants are exposed to certain market risks as major power producers and participants in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk, credit risk and foreign currency exchange risk. These risks represent the risk of loss that may impact the Registrants due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

The Registrants utilize power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. The Registrants utilize interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. The Registrants also utilize derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." 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.

The following tables represent the gross notional volume of the Registrants' outstanding derivative contracts:

Notional Volume of Derivative Instruments
December 31, 2016

Primary Risk Exposure	Unit of Measure	AEP	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Commodity:							
Power	MWhs	348.0	51.9	19.9	11.2	11.9	14.2
Coal	Tons	1.5	—	0.5	—	—	1.0
Natural Gas	MMBtus	32.8	—	—	—	—	—
Heating Oil and Gasoline	Gallons	7.4	1.4	0.7	1.6	0.8	0.9
Interest Rate	USD	$ 75.2	$ 0.1	$ 0.1	$ —	$ —	$ —
Interest Rate and Foreign Currency	USD	$ 500.0	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2015

Primary Risk Exposure	Unit of Measure	AEP	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Commodity:							
Power	MWhs	317.8	40.9	22.8	13.3	11.3	14.0
Coal	Tons	4.4	—	1.6	—	—	2.8
Natural Gas	MMBtus	38.2	0.3	0.2	—	0.2	0.2
Heating Oil and Gasoline	Gallons	7.4	1.4	0.7	1.6	0.8	0.9
Interest Rate	USD	$ 113.5	$ 2.4	$ 1.6	$ —	$ —	$ —
Interest Rate and Foreign Currency	USD	$ 560.3	$ —	$ —	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

Parent enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives may be designated as fair value hedges.

Cash Flow Hedging Strategies

The Registrants utilize cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. The Registrants do not hedge all commodity price risk.

The Registrants utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. The Registrants also utilize interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The Registrants do not hedge all interest rate exposure.

At times, the Registrants are exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, the Registrants may utilize foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrants do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrants apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2016 and 2015 balance sheets, the Registrants netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	December 31,			
	2016		2015	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in millions)			
AEP	$ 7.9	$ 7.6	$ 5.8	$ 44.4
APCo	0.5	0.7	—	3.1
I&M	0.3	0.4	—	0.6
OPCo	0.2	—	—	0.5
PSO	0.1	—	—	0.3
SWEPCo	0.1	—	—	0.3

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets:

AEP

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 264.4	$ 13.2	$ —	$ 277.6	$ (183.1)	$ 94.5
Long-term Risk Management Assets	315.0	7.7	—	322.7	(33.6)	289.1
Total Assets	579.4	20.9	—	600.3	(216.7)	383.6
Current Risk Management Liabilities	227.2	6.3	—	233.5	(180.1)	53.4
Long-term Risk Management Liabilities	301.0	50.1	1.4	352.5	(36.3)	316.2
Total Liabilities	528.2	56.4	1.4	586.0	(216.4)	369.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 51.2	$ (35.5)	$ (1.4)	$ 14.3	$ (0.3)	$ 14.0

AEP

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 368.8	$ 8.2	$ 0.1	$ 377.1	$ (242.7)	$ 134.4
Long-term Risk Management Assets	364.8	11.7	—	376.5	(54.7)	321.8
Total Assets	733.6	19.9	0.1	753.6	(297.4)	456.2
Current Risk Management Liabilities	347.0	9.1	0.3	356.4	(269.3)	87.1
Long-term Risk Management Liabilities	223.3	19.3	3.2	245.8	(66.7)	179.1
Total Liabilities	570.3	28.4	3.5	602.2	(336.0)	266.2
Total MTM Derivative Contract Net Assets (Liabilities)	$ 163.3	$ (8.5)	$ (3.4)	$ 151.4	$ 38.6	$ 190.0

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

(b) Amounts primarily include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

APCo

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets - Nonaffiliated	$ 22.7	$ (20.1)	$ 2.6
Long-term Risk Management Assets - Nonaffiliated	1.9	(1.9)	—
Total Assets	24.6	(22.0)	2.6
Current Risk Management Liabilities - Nonaffiliated	20.6	(20.3)	0.3
Long-term Risk Management Liabilities - Nonaffiliated	2.8	(1.9)	0.9
Total Liabilities	23.4	(22.2)	1.2
Total MTM Derivative Contract Net Assets	$ 1.2	$ 0.2	$ 1.4

APCo

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 25.9	$ (10.3)	$ 15.6
Long-term Risk Management Assets - Nonaffiliated	0.3	(0.2)	0.1
Total Assets	26.2	(10.5)	15.7
Current Risk Management Liabilities - Nonaffiliated	18.1	(13.3)	4.8
Long-term Risk Management Liabilities - Nonaffiliated	0.3	(0.2)	0.1
Total Liabilities	18.4	(13.5)	4.9
Total MTM Derivative Contract Net Assets	$ 7.8	$ 3.0	$ 10.8

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

I&M

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets - Nonaffiliated	$ 14.9	$ (11.4)	$ 3.5
Long-term Risk Management Assets - Nonaffiliated	1.1	(1.1)	—
Total Assets	16.0	(12.5)	3.5
Current Risk Management Liabilities - Nonaffiliated	11.8	(11.5)	0.3
Long-term Risk Management Liabilities - Nonaffiliated	1.9	(1.1)	0.8
Total Liabilities	13.7	(12.6)	1.1
Total MTM Derivative Contract Net Assets	$ 2.3	$ 0.1	$ 2.4

I&M

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets - Nonaffiliated and Affiliated	$ 22.8	$ (10.5)	$ 12.3
Long-term Risk Management Assets - Nonaffiliated	0.6	(0.6)	—
Total Assets	23.4	(11.1)	12.3
Current Risk Management Liabilities - Nonaffiliated	17.0	(10.7)	6.3
Long-term Risk Management Liabilities - Nonaffiliated	2.6	(1.0)	1.6
Total Liabilities	19.6	(11.7)	7.9
Total MTM Derivative Contract Net Assets	$ 3.8	$ 0.6	$ 4.4

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

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for “Derivatives and Hedging.”

(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

OPCo

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.4	$ (0.2)	$ 0.2
Long-term Risk Management Assets	—	—	—
Total Assets	0.4	(0.2)	0.2
Current Risk Management Liabilities	5.9	—	5.9
Long-term Risk Management Liabilities	113.1	—	113.1
Total Liabilities	119.0	—	119.0
Total MTM Derivative Contract Net Liabilities	$ (118.6)	$ (0.2)	$ (118.8)

OPCo

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	19.2	—	19.2
Total Assets	19.2	—	19.2
Current Risk Management Liabilities	4.1	(0.5)	3.6
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	4.1	(0.5)	3.6
Total MTM Derivative Contract Net Assets	$ 15.1	$ 0.5	$ 15.6

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

PSO

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.9	$ (0.1)	$ 0.8
Long-term Risk Management Assets	—	—	—
Total Assets	0.9	(0.1)	0.8
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.9	$ (0.1)	$ 0.8

PSO

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.6	$ —	$ 0.6
Long-term Risk Management Assets	—	—	—
Total Assets	0.6	—	0.6
Current Risk Management Liabilities	0.5	(0.3)	0.2
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.5	(0.3)	0.2
Total MTM Derivative Contract Net Assets	$ 0.1	$ 0.3	$ 0.4

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

SWEPCo

Fair Value of Derivative Instruments
December 31, 2016

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 1.1	$ (0.2)	$ 0.9
Long-term Risk Management Assets	—	—	—
Total Assets	1.1	(0.2)	0.9
Current Risk Management Liabilities	0.4	(0.1)	0.3
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.4	(0.1)	0.3
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.7	$ (0.1)	$ 0.6

SWEPCo

Fair Value of Derivative Instruments
December 31, 2015

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.8	$ —	$ 0.8
Long-term Risk Management Assets	—	—	—
Total Assets	0.8	—	0.8
Current Risk Management Liabilities	3.4	(0.3)	3.1
Long-term Risk Management Liabilities	2.1	—	2.1
Total Liabilities	5.5	(0.3)	5.2
Total MTM Derivative Contract Net Assets (Liabilities)	$ (4.7)	$ 0.3	$ (4.4)

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The tables below present the Registrants' activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2016

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Vertically Integrated Utilities Revenues	$ 4.0	$ —	$ —	$ —	$ —	$ —
Transmission and Distribution Utilities Revenues	0.1	—	—	—	—	—
Generation & Marketing Revenues	59.4	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	(0.6)	4.1	0.1	—	—
Sales to AEP Affiliates	—	2.1	5.8	—	—	—
Purchased Electricity for Resale	6.6	3.5	0.3	—	—	—
Other Operation Expense	(1.6)	(0.1)	(0.1)	(0.3)	(0.1)	(0.3)
Maintenance Expense	(1.8)	(0.4)	(0.1)	(0.4)	(0.2)	(0.2)
Regulatory Assets (a)	(117.4)	0.6	3.1	(127.7)	0.4	5.2
Regulatory Liabilities (a)	79.1	51.4	13.9	(15.2)	6.5	15.7
Total Gain (Loss) on Risk Management Contracts	$ 28.4	$ 56.5	$ 27.0	$ (143.5)	$ 6.6	$ 20.4

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2015

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Vertically Integrated Utilities Revenues	$ 6.7	$ —	$ —	$ —	$ —	$ —
Transmission and Distribution Utilities Revenues	(4.3)	—	—	—	—	—
Generation & Marketing Revenues	54.9	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	1.1	3.3	(4.3)	—	—
Sales to AEP Affiliates	—	2.4	8.2	—	—	—
Purchased Electricity for Resale	6.4	2.0	0.4	—	—	—
Other Operation Expense	(3.3)	(0.4)	(0.4)	(0.6)	(0.4)	(0.5)
Maintenance Expense	(3.3)	(0.7)	(0.4)	(0.5)	(0.4)	(0.4)
Regulatory Assets (a)	(0.9)	3.4	(2.7)	—	0.6	(4.3)
Regulatory Liabilities (a)	30.2	28.7	7.5	(24.7)	4.4	15.1
Total Gain (Loss) on Risk Management Contracts	$ 86.4	$ 36.5	$ 15.9	$ (30.1)	$ 4.2	$ 9.9

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2014

Location of Gain (Loss)	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Vertically Integrated Utilities Revenues	$ 35.4	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	52.5	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	8.7	13.2	—	0.2	—
Sales to AEP Affiliates	—	—	(0.9)	—	0.9	—
Regulatory Assets (a)	(11.4)	(4.1)	(0.5)	—	(1.0)	(1.1)
Regulatory Liabilities (a)	193.2	49.6	37.4	86.0	0.3	16.9
Total Gain on Risk Management Contracts	$ 269.7	$ 54.2	$ 49.2	$ 86.0	$ 0.4	$ 15.8

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

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

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

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

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015, see Note 4 - Rate Matters. These auctions resulted in a range of products, including 12-month, 24-month, and 36-month periods. The delivery period for each contract is scheduled to start on the first day of June of each year, immediately following the auction. Certain affiliated Vertically Integrated Utility and Generation & Marketing segment entities participated in the auction process and were awarded tranches of OPCo's SSO load. Certain underlying contracts are derivatives subject to the accounting guidance for "Derivatives and Hedging" and are accounted for using MTM accounting, unless the contract has been designated as a normal purchase or normal sale.

Accounting for Fair Value Hedging Strategies (Applies to AEP)

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

AEP records realized and unrealized gains or losses on interest rate swaps that are designated and qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income. The following table shows the results of hedging gains (losses):

	Years Ended December 31,		
	2016	2015	2014
		(in millions)	
Gain on Fair Value Hedging Instruments	$ 1.6	$ 3.2	$ 3.8
Loss on Fair Value Portion of Long-term Debt	(1.6)	(3.3)	(3.9)

For 2016, 2015 and 2014, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. The Registrants recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness would be recorded as a regulatory asset (for losses) or a regulatory liability (for gains) if applicable.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2016, 2015 and 2014, AEP applied cash flow hedging to outstanding power derivatives. During 2016 and 2015, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives. During 2014, APCo and I&M applied cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During 2016, 2015 and 2014, AEP applied cash flow hedging to outstanding interest rate derivatives. During 2016, 2015 and 2014, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives.

During 2016, 2015 and 2014, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets were:

Impact of Cash Flow Hedges on AEP's Balance Sheets

	December 31, 2016		December 31, 2015	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
Hedging Assets (a)	$ 11.2	$ —	$ 17.6	$ —
Hedging Liabilities (a)	46.7	—	26.1	0.4
AOCI Gain (Loss) Net of Tax	(23.1)	(15.7)	(5.2)	(17.2)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	4.3	(1.0)	(0.4)	(1.5)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the balance sheets.

As of December 31, 2016 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 132 months.

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Balance Sheets

	December 31, 2016		December 31, 2015	
	Interest Rate and Foreign Currency			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
APCo	$ 2.9	$ 0.7	$ 3.6	$ 0.7
I&M	(12.0)	(1.3)	(13.3)	(1.3)
OPCo	3.0	1.1	4.3	1.2
PSO	3.4	0.8	4.2	0.8
SWEPCo	(7.4)	(1.4)	(9.1)	(1.7)

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

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

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. A counterparty is required to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Credit Downgrade Triggers (Applies to AEP, APCo, I&M, PSO and SWEPCo)

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, additional amounts of collateral are required if certain credit ratings decline below a specified rating threshold. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. AEP, APCo, I&M, PSO and SWEPCo have not experienced a downgrade below a specified rating threshold that would require the posting of additional collateral. There is no exposure relating to derivative contracts, however, there is exposure relating to RTOs, ISOs and non-derivative contracts. The following table represents the exposure if credit ratings were to decline below a specified rating threshold:

	December 31, 2016		December 31, 2015	
Company	Amount of Collateral That Would Have Been Required to Post Attributable to RTOs and ISOs	Amount of Collateral Attributable to Other Contracts	Amount of Collateral That Would Have Been Required to Post Attributable to RTOs and ISOs	Amount of Collateral Attributable to Other Contracts
	(in millions)			
AEP	$ 9.3	$ 280.3 (a)	$ 17.5	$ 297.8 (a)
APCo	1.0	—	4.9	0.1
I&M	0.6	—	3.3	0.1
PSO	2.1	3.2	—	3.2
SWEPCo	2.5	0.1	—	0.1

(a) Represents the amount of collateral AEP subsidiaries would have been required to post for other significant non-derivative contracts including AGR jointly owned plant contracts and various other commodity related contracts.

Cross-Default Triggers (Applies to AEP, APCo and I&M)

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following tables represent: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount that the exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	December 31, 2016		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in millions)	
AEP	$ 259.6	$ 0.4	$ 235.8
APCo	0.1	—	—
I&M	0.1	—	—

	December 31, 2015		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in millions)	
AEP	$ 300.1	$ 0.8	$ 240.6
APCo	3.7	—	3.7
I&M	2.5	—	2.5

11. FAIR VALUE MEASUREMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt are summarized in the following table:

	December 31,			
	2016		2015	
Company	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
AEP	$ 20,391.2 (a)	$ 22,211.9 (a)	$ 19,572.7	$ 21,201.3
APCo	4,033.9	4,613.2	3,930.7	4,416.7
I&M	2,471.4	2,661.6	2,000.0	2,193.6
OPCo	1,763.9	2,092.5	2,157.7	2,472.7
PSO	1,286.0	1,419.0	1,286.1	1,402.9
SWEPCo	2,679.1	2,814.3	2,273.5	2,417.2

(a) Amount includes debt related to the Lawrenceburg Plant that has been classified as Liabilities Held for Sale on the balance sheet and has a fair value of $172 million. See "Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)" section of Note 7 for additional information.

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and securities available for sale, including marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2016			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$ 211.7	$ —	$ —	$ 211.7
Fixed Income Securities – Mutual Funds (b)	92.7	—	(1.0)	91.7
Equity Securities – Mutual Funds	14.4	13.9	—	28.3
Total Other Temporary Investments	$ 318.8	$ 13.9	$ (1.0)	$ 331.7

Other Temporary Investments	December 31, 2015 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$ 271.0	$ —	$ —	$ 271.0
Fixed Income Securities – Mutual Funds (b)	91.1	—	(0.7)	90.4
Equity Securities – Mutual Funds	13.7	11.7	—	25.4
Total Other Temporary Investments	$ 375.8	$ 11.7	$ (0.7)	$ 386.8

(a) Primarily represents amounts held for the repayment of debt.
(b) Primarily short and intermediate maturities which may be sold and do not contain maturity dates.

The following table provides the activity for fixed income and equity securities within Other Temporary Investments:

	Years Ended December 31, 2016	2015	2014
	(in millions)		
Proceeds from Investment Sales	$ —	$ —	$ —
Purchases of Investments	2.3	10.7	1.6
Gross Realized Gains on Investment Sales	—	—	—
Gross Realized Losses on Investment Sales	—	—	—

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the years ended December 31, 2016, 2015 and 2014, see Note 3.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments:

	December 31, 2016			2015		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 18.7	$ —	$ —	$ 168.3	$ —	$ —
Fixed Income Securities:						
United States Government	785.4	27.1	(5.5)	731.1	35.9	(2.6)
Corporate Debt	60.9	2.3	(1.4)	57.9	3.2	(1.1)
State and Local Government	121.1	0.4	(0.7)	22.2	1.1	(0.3)
Subtotal Fixed Income Securities	967.4	29.8	(7.6)	811.2	40.2	(4.0)
Equity Securities – Domestic	1,270.1	677.9	(79.6)	1,126.9	571.6	(79.3)
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,256.2	$ 707.7	$ (87.2)	$ 2,106.4	$ 611.8	$ (83.3)

The following table provides the securities activity within the decommissioning and SNF trusts:

	Years Ended December 31, 2016	2015	2014
		(in millions)	
Proceeds from Investment Sales	$ 2,957.7	$ 2,218.4	$ 1,031.8
Purchases of Investments	3,000.0	2,272.0	1,086.4
Gross Realized Gains on Investment Sales	46.1	69.1	32.3
Gross Realized Losses on Investment Sales	24.4	53.0	15.4

The base cost of fixed income securities was $938 million and $771 million as of December 31, 2016 and 2015, respectively. The base cost of equity securities was $592 million and $555 million as of December 31, 2016 and 2015, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2016 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 229.5
1 year – 5 years	335.3
5 years – 10 years	204.6
After 10 years	198.0
Total	$ 967.4

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 8.7	$ —	$ —	$ 201.8	$ 210.5
Other Temporary Investments					
Restricted Cash (a)	173.8	5.1	—	32.8	211.7
Fixed Income Securities – Mutual Funds	91.7	—	—	—	91.7
Equity Securities – Mutual Funds (b)	28.3	—	—	—	28.3
Total Other Temporary Investments	293.8	5.1	—	32.8	331.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	6.0	379.9	192.2	(205.7)	372.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	16.8	1.7	(7.3)	11.2
Total Risk Management Assets	6.0	396.7	193.9	(213.0)	383.6
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.3	—	—	11.4	18.7
Fixed Income Securities:					
United States Government	—	785.4	—	—	785.4
Corporate Debt	—	60.9	—	—	60.9
State and Local Government	—	121.1	—	—	121.1
Subtotal Fixed Income Securities	—	967.4	—	—	967.4
Equity Securities – Domestic (b)	1,270.1	—	—	—	1,270.1
Total Spent Nuclear Fuel and Decommissioning Trusts	1,277.4	967.4	—	11.4	2,256.2
Total Assets	$ 1,585.9	$ 1,369.2	$ 193.9	$ 33.0	$ 3,182.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 8.2	$ 352.0	$ 166.7	$ (205.4)	$ 321.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	29.3	24.7	(7.3)	46.7
Fair Value Hedges	—	1.4	—	—	1.4
Total Risk Management Liabilities	$ 8.2	$ 382.7	$ 191.4	$ (212.7)	$ 369.6

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 3.9	$ 4.3	$ —	$ 168.2	$ 176.4
Other Temporary Investments					
Restricted Cash (a)	230.0	7.7	—	33.3	271.0
Fixed Income Securities – Mutual Funds	90.4	—	—	—	90.4
Equity Securities – Mutual Funds (b)	25.4	—	—	—	25.4
Total Other Temporary Investments	345.8	7.7	—	33.3	386.8
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	11.5	495.0	219.7	(287.7)	438.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	15.9	1.0	0.7	17.6
Fair Value Hedges	—	—	—	0.1	0.1
Total Risk Management Assets	11.5	510.9	220.7	(286.9)	456.2
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	160.5	—	—	7.8	168.3
Fixed Income Securities:					
United States Government	—	731.1	—	—	731.1
Corporate Debt	—	57.9	—	—	57.9
State and Local Government	—	22.2	—	—	22.2
Subtotal Fixed Income Securities	—	811.2	—	—	811.2
Equity Securities – Domestic (b)	1,126.9	—	—	—	1,126.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,287.4	811.2	—	7.8	2,106.4
Total Assets	$ 1,648.6	$ 1,334.1	$ 220.7	$ (77.6)	$ 3,125.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 24.1	$ 471.5	$ 67.3	$ (326.3)	$ 236.6
Cash Flow Hedges:					
Commodity Hedges (c)	—	18.9	6.5	0.7	26.1
Interest Rate/Foreign Currency Hedges	—	0.4	—	—	0.4
Fair Value Hedges	—	3.0	—	0.1	3.1
Total Risk Management Liabilities	$ 24.1	$ 493.8	$ 73.8	$ (325.5)	$ 266.2

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding (a)	$ 15.8	$ —	$ —	$ 0.1	$ 15.9
Risk Management Assets – Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	—	20.5	3.9	(21.8)	2.6
Total Assets	$ 15.8	$ 20.5	$ 3.9	$ (21.7)	$ 18.5
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$ —	$ 20.7	$ 2.5	$ (22.0)	$ 1.2

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding (a)	$ 14.8	$ —	$ —	$ 0.1	$ 14.9
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (c) (g)	0.2	13.9	12.2	(10.6)	15.7
Total Assets	$ 15.0	$ 13.9	$ 12.2	$ (10.5)	$ 30.6
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$ 0.2	$ 17.8	$ 0.5	$ (13.6)	$ 4.9

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets – Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$ —	$ 12.8	$ 3.0	$ (12.3)	$ 3.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.3	—	—	11.4	18.7
Fixed Income Securities:					
United States Government	—	785.4	—	—	785.4
Corporate Debt	—	60.9	—	—	60.9
State and Local Government	—	121.1	—	—	121.1
Subtotal Fixed Income Securities	—	967.4	—	—	967.4
Equity Securities – Domestic (b)	1,270.1	—	—	—	1,270.1
Total Spent Nuclear Fuel and Decommissioning Trusts	1,277.4	967.4	—	11.4	2,256.2
Total Assets	$ 1,277.4	$ 980.2	$ 3.0	$ (0.9)	$ 2,259.7
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$ —	$ 13.3	$ 0.2	$ (12.4)	$ 1.1

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets – Nonaffiliated and Affiliated					
Risk Management Commodity Contracts (c) (g)	$ 0.1	$ 17.0	$ 6.3	$ (11.1)	$ 12.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	160.5	—	—	7.8	168.3
Fixed Income Securities:					
United States Government	—	731.1	—	—	731.1
Corporate Debt	—	57.9	—	—	57.9
State and Local Government	—	22.2	—	—	22.2
Subtotal Fixed Income Securities	—	811.2	—	—	811.2
Equity Securities – Domestic (b)	1,126.9	—	—	—	1,126.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,287.4	811.2	—	7.8	2,106.4
Total Assets	$ 1,287.5	$ 828.2	$ 6.3	$ (3.3)	$ 2,118.7
Liabilities:					
Risk Management Liabilities – Nonaffiliated					
Risk Management Commodity Contracts (c) (g)	$ 0.1	$ 17.5	$ 2.0	$ (11.7)	$ 7.9

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding (a)	$ —	$ —	$ —	$ 27.2	$ 27.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.4	—	(0.2)	0.2
Total Assets	$ —	$ 0.4	$ —	$ 27.0	$ 27.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 119.0	$ —	$ 119.0

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding (a)	$ —	$ —	$ —	$ 27.7	$ 27.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	—	16.0	3.2	19.2
Total Assets	$ —	$ —	$ 16.0	$ 30.9	$ 46.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.8	$ 0.1	$ 2.7	$ 3.6

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 0.7	$ (0.1)	$ 0.8

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.7	$ (0.1)	$ 0.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.5	$ 0.1	$ (0.4)	$ 0.2

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2016

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 8.7	$ —	$ —	$ 1.6	$ 10.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.3	0.8	(0.2)	0.9
Total Assets	$ 8.7	$ 0.3	$ 0.8	$ 1.4	$ 11.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 0.1	$ (0.1)	$ 0.3

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2015

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 3.6	$ —	$ —	$ 1.6	$ 5.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	—	0.9	(0.1)	0.8
Total Assets	$ 3.6	$ —	$ 0.9	$ 1.5	$ 6.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 5.5	$ 0.1	$ (0.4)	$ 5.2

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(d) The December 31, 2016 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(2) million in 2018-2020; Level 2 matures $20 million in 2017, $4 million in periods 2018-2020, $3 million in periods 2021-2022 and $1 million in periods 2023-2032; Level 3 matures $17 million in 2017, $28 million in periods 2018-2020, $11 million in periods 2021-2022 and $(31) million in periods 2023-2032. Risk management commodity contracts are substantially comprised of power contracts.
(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.
(f) The December 31, 2015 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(9) million in 2016 and $(4) million in periods 2017-2019; Level 2 matures $2 million in 2016, $18 million in periods 2017-2019 and $4 million in periods 2020-2021; Level 3 matures $28 million in 2016, $29 million in periods 2017-2019, $19 million in periods 2020-2021 and $76 million in periods 2022-2032. Risk management commodity contracts are substantially comprised of power contracts.
(g) Substantially comprised of power contracts for the Registrant Subsidiaries.

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2016, 2015 and 2014.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2016	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2015	$ 146.9	$ 11.7	$ 4.3	$ 15.9	$ 0.6	$ 0.8
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	42.8	25.6	7.1	(3.0)	(1.0)	7.7
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	26.1	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(23.0)	—	—	—	—	—
Settlements	(71.4)	(37.5)	(11.1)	6.2	0.4	(8.4)
Transfers into Level 3 (d) (e)	13.3	—	—	—	—	—
Transfers out of Level 3 (e)	(2.6)	0.1	0.1	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(129.6)	1.5	2.4	(138.1)	0.7	0.6
Balance as of December 31, 2016	$ 2.5	$ 1.4	$ 2.8	$ (119.0)	$ 0.7	$ 0.7

Year Ended December 31, 2015	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2014	$ 150.8	$ 15.8	$ 14.7	$ 48.4	$ (0.3)	$ (0.5)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	13.5	2.1	0.2	0.5	(0.2)	9.2
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	53.7	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(4.9)	—	—	—	—	—
Settlements	(63.0)	(17.2)	(14.2)	(6.7)	0.6	(8.7)
Transfers into Level 3 (d) (e)	28.7	—	—	—	—	—
Transfers out of Level 3 (e)	(18.9)	1.2	0.8	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(13.0)	9.8	2.8	(26.3)	0.5	0.8
Balance as of December 31, 2015	$ 146.9	$ 11.7	$ 4.3	$ 15.9	$ 0.6	$ 0.8

Year Ended December 31, 2014	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2013	$ 117.9	$ 10.6	$ 7.2	$ 2.9	$ —	$ —
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	90.0	29.7	18.6	30.8	—	—
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	0.7	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	5.7	—	—	—	—	—
Settlements	(108.7)	(32.6)	(20.6)	(33.7)	—	—
Transfers into Level 3 (d) (e)	(7.6)	(3.6)	(2.5)	—	—	—
Transfers out of Level 3 (e)	(21.5)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	74.3	11.7	12.0	48.4	(0.3)	(0.5)
Balance as of December 31, 2014	$ 150.8	$ 15.8	$ 14.7	$ 48.4	$ (0.3)	$ (0.5)

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on the statements of income.
(c) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
December 31, 2016

AEP

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 183.8	$ 187.1	Discounted Cash Flow	Forward Market Price (a)	$ 6.51	$ 86.59	$ 39.40
				Counterparty Credit Risk (b)	35	824	391
FTRs	10.1	4.3	Discounted Cash Flow	Forward Market Price (a)	(7.99)	8.91	0.86
Total	$ 193.9	$ 191.4					

Significant Unobservable Inputs
December 31, 2015

AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 212.3	$ 70.3	Discounted Cash Flow	Forward Market Price (a)	$ 9.69	$ 165.36	$ 36.35
				Counterparty Credit Risk (c)		670	
FTRs	8.4	3.5	Discounted Cash Flow	Forward Market Price (a)	(6.99)	10.34	1.10
Total	$ 220.7	$ 73.8					

Significant Unobservable Inputs
December 31, 2016

APCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 0.4	$ 0.4	Discounted Cash Flow	Forward Market Price	$ 19.68	$ 48.55	$ 36.34
FTRs	3.5	2.1	Discounted Cash Flow	Forward Market Price	(0.23)	8.91	2.37
Total	$ 3.9	$ 2.5					

Significant Unobservable Inputs
December 31, 2015

APCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 7.9	$ 0.2	Discounted Cash Flow	Forward Market Price	$ 12.61	$ 47.24	$ 32.38
FTRs	4.3	0.3	Discounted Cash Flow	Forward Market Price	(6.96)	8.43	1.34
Total	$ 12.2	$ 0.5					

Significant Unobservable Inputs
December 31, 2016

I&M

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 0.3	$ 0.2	Discounted Cash Flow	Forward Market Price	$ 19.68	$ 48.55	$ 36.34
FTRs	2.7	—	Discounted Cash Flow	Forward Market Price	(7.90)	8.91	1.32
Total	$ 3.0	$ 0.2					

Significant Unobservable Inputs
December 31, 2015

I&M

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 6.0	$ 0.2	Discounted Cash Flow	Forward Market Price	$ 12.61	$ 47.24	$ 32.38
FTRs	0.3	1.8	Discounted Cash Flow	Forward Market Price	(6.96)	8.43	1.34
Total	$ 6.3	$ 2.0					

Significant Unobservable Inputs
December 31, 2016

OPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 119.0	Discounted Cash Flow	Forward Market Price (a)	$ 30.14	$ 71.85	$ 47.45
				Counterparty Credit Risk (b)	47	340	272
Total	$ —	$ 119.0					

Significant Unobservable Inputs
December 31, 2015

OPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 16.0	$ 0.1	Discounted Cash Flow	Forward Market Price	$ 41.61	$ 165.36	$ 86.84

Significant Unobservable Inputs
December 31, 2016

PSO

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 0.7	$ —	Discounted Cash Flow	Forward Market Price	$ (7.99)	$ 1.03	$ (0.36)

Significant Unobservable Inputs
December 31, 2015

PSO

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 0.7	$ 0.1	Discounted Cash Flow	Forward Market Price	$ (6.96)	$ 8.43	$ 1.34

Significant Unobservable Inputs
December 31, 2016

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 0.8	$ 0.1	Discounted Cash Flow	Forward Market Price	$ (7.99)	$ 1.03	$ (0.36)

Significant Unobservable Inputs
December 31, 2015

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 0.9	$ 0.1	Discounted Cash Flow	Forward Market Price	$ (6.96)	$ 8.43	$ 1.34

(a) Represents market prices in dollars per MWh.
(b) Represents prices of credit default swaps used to calculate counterparty credit risk, reported in basis points.
(c) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs for the Registrants as of December 31, 2016 and 2015:

Sensitivity of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)
Counterparty Credit Risk	Loss	Increase (Decrease)	Higher (Lower)
Counterparty Credit Risk	Gain	Increase (Decrease)	Lower (Higher)

12. INCOME TAXES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Income Tax Expense (Credit)

The details of the Registrants' income tax expense (credit) before discontinued operations as reported are as follows:

Year Ended December 31, 2016	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Federal:						
Current	$ (30.7)	$ 64.1	$ (44.8)	$ 178.8	$ (28.0)	$ (96.7)
Deferred	(28.8)	125.8	104.9	(40.8)	77.2	172.6
Deferred Investment Tax Credits	17.6	(0.1)	3.8	—	(1.4)	(1.2)
Total Federal	(41.9)	189.8	63.9	138.0	47.8	74.7
State and Local:						
Current	(10.5)	4.4	3.4	4.2	(1.9)	(12.6)
Deferred	(21.2)	4.9	0.2	1.6	5.3	(10.0)
Deferred Investment Tax Credits	(0.1)	—	—	—	3.2	—
Total State and Local	(31.8)	9.3	3.6	5.8	6.6	(22.6)
Income Tax Expense (Credit) Before Discontinued Operations	$ (73.7)	$ 199.1	$ 67.5	$ 143.8	$ 54.4	$ 52.1

AEP	Years Ended December 31, 2015	2014
	(in millions)	
Federal:		
Current	$ 107.3	$ 22.8
Deferred	774.8	800.1
Total Federal	882.1	822.9
State and Local:		
Current	14.5	22.8
Deferred	23.0	56.9
Total State and Local	37.5	79.7
Income Tax Expense Before Discontinued Operations	$ 919.6	$ 902.6

Year Ended December 31, 2015	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)		
Income Tax Expense (Credit):					
Current	$ (32.9)	$ 5.2	$ 89.0	$ (6.4)	$ 44.3
Deferred	227.5	94.2	37.6	58.3	41.9
Deferred Investment Tax Credits	(0.3)	(3.3)	(0.1)	(0.6)	(1.4)
Income Tax Expense	$ 194.3	$ 96.1	$ 126.5	$ 51.3	$ 84.8

Year Ended December 31, 2014	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)		
Income Tax Expense (Credit):					
Current	$ 10.9	$ 14.3	$ 58.1	$ (24.2)	$ (171.6)
Deferred	144.7	70.2	74.4	74.7	239.4
Deferred Investment Tax Credits	(0.7)	(4.9)	(0.3)	0.1	(1.4)
Income Tax Expense	$ 154.9	$ 79.6	$ 132.2	$ 50.6	$ 66.4

The following is a reconciliation for each Registrant of the difference between the amounts of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

AEP	Years Ended December 31, 2016	2015	2014
		(in millions)	
Net Income	$ 618.0	$ 2,052.3	$ 1,638.0
Discontinued Operations (Net of Income Tax of $0, $6.2 and $39 in 2016, 2015 and 2014, Respectively)	2.5	(283.7)	(47.5)
Income Tax Expense (Credit) Before Discontinued Operations	(73.7)	919.6	902.6
Pretax Income	$ 546.8	$ 2,688.2	$ 2,493.1
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 191.4	$ 940.9	$ 872.6
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	41.7	53.6	54.0
Investment Tax Credits, Net	(12.3)	(11.6)	(12.8)
State and Local Income Taxes, Net	(20.7)	24.4	54.3
Removal Costs	(39.8)	(28.8)	(23.9)
AFUDC	(44.8)	(51.6)	(41.8)
Valuation Allowance	(128.3)	17.2	(2.5)
U.K. Windfall Tax	(12.9)	—	—
Tax Adjustments	(43.9)	(20.1)	(10.1)
Other	(4.1)	(4.4)	12.8
Income Tax Expense (Credit) Before Discontinued Operations	$ (73.7)	$ 919.6	$ 902.6
Effective Income Tax Rate	(13.5)%	34.2 %	36.2 %

APCo	Years Ended December 31, 2016	2015	2014
		(in millions)	
Net Income	$ 369.1	$ 340.6	$ 215.4
Income Tax Expense	199.1	194.3	154.9
Pretax Income	$ 568.2	$ 534.9	$ 370.3
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 198.9	$ 187.2	$ 129.6
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	19.3	19.8	23.5
Investment Tax Credits, Net	(0.1)	(0.3)	(0.6)
State and Local Income Taxes, Net	6.0	7.2	6.5
Removal Costs	(12.0)	(9.9)	(6.8)
AFUDC	(6.1)	(7.0)	(3.8)
Valuation Allowance	(1.7)	1.7	(2.5)
Other	(5.2)	(4.4)	9.0
Income Tax Expense	$ 199.1	$ 194.3	$ 154.9
Effective Income Tax Rate	35.0 %	36.3 %	41.8 %

I&M

	Years Ended December 31, 2016	2015	2014
		(in millions)	
Net Income	$ 239.9	$ 204.8	$ 155.6
Income Tax Expense	67.5	96.1	79.6
Pretax Income	$ 307.4	$ 300.9	$ 235.2
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 107.6	$ 105.3	$ 82.3
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	6.7	9.5	12.9
Investment Tax Credits, Net	(4.7)	(3.3)	(4.9)
State and Local Income Taxes, Net	2.4	5.8	7.7
Removal Costs	(21.3)	(12.6)	(11.3)
AFUDC	(7.3)	(6.2)	(10.0)
Tax Adjustments	(14.2)	(4.2)	1.2
Other	(1.7)	1.8	1.7
Income Tax Expense	$ 67.5	$ 96.1	$ 79.6
Effective Income Tax Rate	22.0 %	31.9 %	33.8 %

OPCo

	Years Ended December 31, 2016	2015	2014
		(in millions)	
Net Income	$ 282.2	$ 232.7	$ 216.4
Income Tax Expense	143.8	126.5	132.2
Pretax Income	$ 426.0	$ 359.2	$ 348.6
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 149.1	$ 125.7	$ 122.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	7.1	8.2	6.7
Investment Tax Credits, Net	—	(0.1)	(0.2)
State and Local Income Taxes, Net	3.8	0.7	8.8
Other	(16.2)	(8.0)	(5.1)
Income Tax Expense	$ 143.8	$ 126.5	$ 132.2
Effective Income Tax Rate	33.8 %	35.2 %	37.9 %

PSO

	Years Ended December 31, 2016	2015	2014
		(in millions)	
Net Income	$ 100.0	$ 92.5	$ 86.9
Income Tax Expense	54.4	51.3	50.6
Pretax Income	$ 154.4	$ 143.8	$ 137.5
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 54.0	$ 50.3	$ 48.1
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	0.8	0.5	0.2
Investment Tax Credits, Net	(1.4)	(1.8)	(0.8)
State and Local Income Taxes, Net	4.2	5.1	4.8
AFUDC	(2.2)	(3.1)	(1.1)
Other	(1.0)	0.3	(0.6)
Income Tax Expense	$ 54.4	$ 51.3	$ 50.6
Effective Income Tax Rate	35.2 %	35.7 %	36.8 %

SWEPCo	Years Ended December 31,		
	2016	2015	2014
		(in millions)	
Net Income	$ 169.7	$ 196.0	$ 144.6
Income Tax Expense	52.1	84.8	66.4
Pretax Income	$ 221.8	$ 280.8	$ 211.0
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 77.6	$ 98.3	$ 73.8
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	3.2	3.1	2.9
Depletion	(5.5)	(5.5)	(4.1)
Investment Tax Credits, Net	(1.2)	(1.4)	(1.4)
State and Local Income Taxes, Net	(14.7)	4.8	3.1
AFUDC	(3.9)	(9.2)	(4.2)
Other	(3.4)	(5.3)	(3.7)
Income Tax Expense	$ 52.1	$ 84.8	$ 66.4
Effective Income Tax Rate	23.5 %	30.2 %	31.5 %

Net Deferred Tax Liability

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant:

AEP	December 31,	
	2016	2015
	(in millions)	
Deferred Tax Assets	$ 2,753.0	$ 2,503.9
Deferred Tax Liabilities	(14,637.4)	(14,237.1)
Net Deferred Tax Liabilities	$ (11,884.4)	$ (11,733.2)
Property Related Temporary Differences	$ (8,758.1)	$ (8,533.3)
Amounts Due from Customers for Future Federal Income Taxes	(292.2)	(263.5)
Deferred State Income Taxes	(976.6)	(872.0)
Securitized Assets	(535.6)	(633.2)
Regulatory Assets	(896.9)	(873.6)
Deferred Income Taxes on Other Comprehensive Loss	88.7	72.2
Accrued Nuclear Decommissioning	(666.8)	(614.6)
Net Operating Loss Carryforward	101.2	39.6
Tax Credit Carryforward	45.1	85.0
Valuation Allowance	(1.8)	(130.0)
All Other, Net	8.6	(9.8)
Net Deferred Tax Liabilities	$ (11,884.4)	$ (11,733.2)

APCo

	December 31, 2016	December 31, 2015
	(in millions)	
Deferred Tax Assets	$ 413.5	$ 412.9
Deferred Tax Liabilities	(3,085.8)	(2,939.9)
Net Deferred Tax Liabilities	$ (2,672.3)	$ (2,527.0)
Property Related Temporary Differences	$ (2,031.9)	$ (1,866.0)
Amounts Due from Customers for Future Federal Income Taxes	(73.1)	(68.2)
Deferred State Income Taxes	(319.3)	(308.7)
Regulatory Assets	(159.9)	(169.1)
Securitized Assets	(106.9)	(114.8)
Deferred Income Taxes on Other Comprehensive Loss	4.5	1.5
Tax Credit Carryforward	11.7	19.2
All Other, Net	2.6	(20.9)
Net Deferred Tax Liabilities	$ (2,672.3)	$ (2,527.0)

I&M

	December 31, 2016	December 31, 2015
	(in millions)	
Deferred Tax Assets	$ 912.9	$ 837.4
Deferred Tax Liabilities	(2,440.3)	(2,198.9)
Net Deferred Tax Liabilities	$ (1,527.4)	$ (1,361.5)
Property Related Temporary Differences	$ (579.4)	$ (521.6)
Amounts Due from Customers for Future Federal Income Taxes	(50.4)	(42.7)
Deferred State Income Taxes	(158.7)	(124.8)
Deferred Income Taxes on Other Comprehensive Loss	8.8	9.0
Accrued Nuclear Decommissioning	(666.8)	(614.6)
Regulatory Assets	(81.0)	(70.2)
Net Operating Loss Carryforward	7.1	—
All Other, Net	(7.0)	3.4
Net Deferred Tax Liabilities	$ (1,527.4)	$ (1,361.5)

OPCo

	December 31, 2016	December 31, 2015
	(in millions)	
Deferred Tax Assets	$ 232.4	$ 162.4
Deferred Tax Liabilities	(1,578.5)	(1,545.6)
Net Deferred Tax Liabilities	$ (1,346.1)	$ (1,383.2)
Property Related Temporary Differences	$ (1,090.8)	$ (1,022.8)
Amounts Due from Customers for Future Federal Income Taxes	(43.6)	(44.6)
Deferred State Income Taxes	(34.6)	(34.4)
Regulatory Assets	(174.1)	(220.0)
Deferred Income Taxes on Other Comprehensive Loss	(1.6)	(2.3)
Deferred Fuel and Purchased Power	(117.6)	(117.4)
All Other, Net	116.2	58.3
Net Deferred Tax Liabilities	$ (1,346.1)	$ (1,383.2)

PSO	December 31, 2016	December 31, 2015
	(in millions)	
Deferred Tax Assets	$ 153.8	$ 141.2
Deferred Tax Liabilities	(1,212.6)	(1,113.0)
Net Deferred Tax Liabilities	$ (1,058.8)	$ (971.8)
Property Related Temporary Differences	$ (927.3)	$ (861.9)
Amounts Due from Customers for Future Federal Income Taxes	(3.2)	(2.2)
Deferred State Income Taxes	(128.5)	(117.0)
Regulatory Assets	(67.6)	(54.3)
Deferred Income Taxes on Other Comprehensive Loss	(1.8)	(2.3)
Deferred Federal Income Taxes on Deferred State Income Taxes	50.6	46.6
Net Operating Loss Carryforward	16.5	7.1
Tax Credit Carryforward	—	0.6
All Other, Net	2.5	11.6
Net Deferred Tax Liabilities	$ (1,058.8)	$ (971.8)

SWEPCo	December 31, 2016	December 31, 2015
	(in millions)	
Deferred Tax Assets	$ 230.5	$ 194.7
Deferred Tax Liabilities	(1,837.4)	(1,594.5)
Net Deferred Tax Liabilities	$ (1,606.9)	$ (1,399.8)
Property Related Temporary Differences	$ (1,445.2)	$ (1,275.1)
Amounts Due from Customers for Future Federal Income Taxes	(48.2)	(47.8)
Deferred State Income Taxes	(175.1)	(132.3)
Regulatory Assets	(40.7)	(26.1)
Deferred Income Taxes on Other Comprehensive Loss	5.1	5.0
Impairment Loss - Turk Plant	20.3	20.7
Net Operating Loss Carryforward	40.3	19.7
Tax Credit Carryforward	0.1	0.7
All Other, Net	36.5	35.4
Net Deferred Tax Liabilities	$ (1,606.9)	$ (1,399.8)

AEP System Tax Allocation Agreement

AEP and subsidiaries join in the filing of a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss and the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Valuation Allowance

AEP assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective negative evidence evaluated includes whether AEP has a history of recognizing income of the character which can be offset by loss carryforwards. Other objective negative evidence evaluated is the impact recently enacted federal tax legislation will have on future taxable income and on AEP's ability to benefit from the carryforward of charitable contribution deductions.

On the basis of this evaluation, AEP recorded a valuation allowance of $17 million in the fourth quarter of 2015 related to the expected expiration of charitable contribution carryforward deductions and realized capital losses. In the fourth quarter of 2015 AEP also reversed a valuation allowance originally recorded in the third quarter of 2015 of $156 million attributable to the unrealized capital loss associated with the excess tax basis of the stock over the book value of AEP's investment in the operations of AEPRO. With the sale of AEPRO in the fourth quarter of 2015, AEP recorded a valuation allowance of $48 million attributable to realized capital losses from the sale. As of December 31, 2015 there was a valuation allowance of $130 million recorded against AEP's deferred tax asset balance.

AEP recorded changes in the valuation allowance in the second quarter of 2016 related to the reversal of a $56 million unrealized capital loss where AEP effectively settled a 2011 audit issue with the IRS. AEP also recorded changes in the third quarter of 2016 by reducing the capital loss valuation allowance by $66 million to reflect the impact of the reclassification of certain assets held for sale and the filing of the 2015 federal income tax return. The sale of these assets held for sale are expected to result in a gain, the character of which will allow AEP to recognize the capital loss and allowed AEP to reverse substantially all of the remaining capital loss valuation allowance previously recorded. During the fourth quarter of 2016, AEP reversed $6 million of the valuation allowance associated with charitable contributions that expired at the end of the year. As of December 31, 2016 there was a valuation allowance of $2 million recorded against AEP's deferred tax asset balance related to an unrealized capital loss carryforward.

Federal and State Income Tax Audit Status

AEP and subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011, 2012 and 2013 started in April 2014. AEP and subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. The Joint Committee referred the audit back to the IRS exam team for further consideration. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrants accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

AEP and subsidiaries file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine their tax returns. AEP and subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. The Registrants are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2009.

Net Income Tax Operating Loss Carryforward

In 2016, AEP, I&M, PSO and SWEPCo recognized federal net income tax operating losses of $143 million, $20 million, $17 million and $37 million, respectively, which were driven primarily by bonus depreciation. As of December 31, 2016, AEP, I&M, PSO and SWEPCo had $50 million, $7 million, $6 million and $13 million, respectively, of unrealized federal net operating loss carryforward tax benefits. Management anticipates future taxable income will be sufficient to realize the remaining net income tax operating loss tax benefits before the federal carryforward expires after 2036. AEP, PSO and SWEPCo also have state net income tax operating loss carryforwards as of December 31, 2016 as indicated in the table below:

Company	State	State Net Income Tax Operating Loss Carryforward	Year of Expiration
		(in millions)	
AEP	Arkansas	$ 16.7	2021
AEP	Kentucky	89.7	2036
AEP	Louisiana	509.1	2036
AEP	Missouri	6.3	2036
AEP	Oklahoma	529.9	2036
PSO	Oklahoma	273.2	2036
SWEPCo	Arkansas	16.2	2021
SWEPCo	Louisiana	508.3	2036
SWEPCo	Oklahoma	4.2	2036

Management anticipates future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the state carryforward expires for each state.

As of December 31, 2013, AEP had $121 million of uncertain tax positions netted against the federal net income tax operating loss carryforward tax benefits. Due to the utilization of the net operating loss carryforward in 2014, $69 million is presented as a non-current uncertain tax position. As of December 31, 2016 and 2015, AEP had $17 million and $59 million, respectively, of uncertain tax positions netted against deferred tax liabilities.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2012, 2011 and 2009 along with lower federal and state taxable income in 2010 resulted in unused federal and state income tax credits. As of December 31, 2016, the Registrants have federal tax credit carryforwards and AEP and PSO have state tax credit carryforwards as indicated in the table below. If these credits are not utilized, federal general business tax credits will expire in the years 2032 through 2036.

Company	Total Federal Tax Credit Carryforward	Federal Tax Credit Carryforward Subject to Expiration	Total State Tax Credit Carryforward	State Tax Credit Carryforward Subject to Expiration
		(in millions)		
AEP	$ 53.6	$ 34.3	$ 26.6	$ 26.6
APCo	11.7	4.5	—	—
I&M	9.0	8.5	—	—
OPCo	8.6	—	—	—
PSO	—	—	26.6	26.6
SWEPCo	0.1	—	—	—

The Registrants anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused. In November 2014, APCo received an order from the Virginia SCC for its 2014 Virginia Biennial Base Rate Case (see Note 4). As a result of the final determination pertaining to the ability to realize future tax benefits for certain state net income tax operating loss and credit carryforwards, management determined that APCo is subject to the Virginia Minimum Tax on electric suppliers and the Virginia State Income Tax is no longer applicable. As a result, management derecognized the related state income tax benefits, which had been subject to valuation allowances.

Uncertain Tax Positions

In May 2013, the U.S. Supreme Court decided that the U.K. Windfall Tax imposed upon U.K. electric companies privatized between 1984 and 1996 is a creditable tax for U.S. federal income tax purposes. AEP filed protective claims asserting the creditability of the tax, dependent upon the outcome of the case. As a result of the favorable U.S. Supreme Court decision, AEP recognized a tax benefit of $80 million, plus $43 million of pretax interest income in the second quarter of 2013. In the first quarter of 2017, AEP received the tax refund related to the U.K. Windfall Tax, including interest through the date of the refund.

The Registrants recognize interest accruals related to uncertain tax positions in interest income or expense as applicable and penalties in Other Operation expense in accordance with the accounting guidance for "Income Taxes."

The following tables show amounts reported for interest expense, interest income and reversal of prior period interest expense:

Year Ended December 31, 2016	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Interest Expense	$ 2.7	$ —	$ 0.2	$ 0.2	$ —	$ —
Interest Income	9.9	0.1	—	—	0.3	—
Reversal of Prior Period Interest Expense	3.3	—	—	—	0.7	1.4

Year Ended December 31, 2015	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Interest Expense	$ 2.7	$ 0.4	$ 0.2	$ 1.0	$ 0.1	$ 0.4
Interest Income	0.8	—	—	—	—	—
Reversal of Prior Period Interest Expense	—	—	—	—	—	—

Year Ended December 31, 2014	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Interest Expense	$ 2.9	$ —	$ —	$ 0.1	$ 0.1	$ 0.2
Interest Income	1.2	—	—	—	—	—
Reversal of Prior Period Interest Expense	2.0	0.2	0.3	0.2	0.1	0.2

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	Years Ended December 31,			
	2016		2015	
Company	Receipt of Interest	Payment of Interest and Penalties	Receipt of Interest	Payment of Interest and Penalties
	(in millions)			
AEP	$ 2.9	$ 5.8	$ 44.7	$ 7.2
APCo	—	0.1	—	—
I&M	—	0.9	—	0.6
OPCo	—	1.7	—	0.6
PSO	0.6	—	—	0.4
SWEPCo	0.1	—	—	1.4

The reconciliations of the beginning and ending amounts of unrecognized tax benefits are as follows:

	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of January 1, 2016	$ 187.0	$ 0.3	$ 2.4	$ 6.9	$ 1.3	$ 9.3
Increase – Tax Positions Taken During a Prior Period	86.0	—	1.8	—	0.1	1.3
Decrease – Tax Positions Taken During a Prior Period	(161.2)	(0.3)	(0.4)	—	(1.3)	(9.3)
Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	(13.0)	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—
Balance as of December 31, 2016	$ 98.8	$ —	$ 3.8	$ 6.9	$ 0.1	$ 1.3

	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of January 1, 2015	$ 182.0	$ —	$ 2.3	$ 6.9	$ 1.3	$ 7.5
Increase – Tax Positions Taken During a Prior Period	5.4	0.3	0.1	—	—	1.8
Decrease – Tax Positions Taken During a Prior Period	(0.4)	—	—	—	—	—
Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—
Balance as of December 31, 2015	$ 187.0	$ 0.3	$ 2.4	$ 6.9	$ 1.3	$ 9.3

	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of January 1, 2014	$ 175.2	$ 1.2	$ 3.2	$ 2.1	$ 2.2	$ 7.6
Increase – Tax Positions Taken During a Prior Period	18.2	—	1.4	6.4	—	1.6
Decrease – Tax Positions Taken During a Prior Period	(1.5)	—	—	—	—	(0.8)
Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	(0.6)	—	(0.7)	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	(9.3)	(1.2)	(1.6)	(1.6)	(0.9)	(0.9)
Balance as of December 31, 2014	$ 182.0	$ —	$ 2.3	$ 6.9	$ 1.3	$ 7.5

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant was as follows:

Company	2016	2015	2014
		(in millions)	
AEP	$ 15.8	$ 100.2	$ 97.2
APCo	—	0.2	—
I&M	2.5	1.6	1.6
OPCo	4.4	4.5	4.5
PSO	0.1	0.9	0.9
SWEPCo	0.8	6.0	4.9

Federal Tax Legislation

The Tax Increase Prevention Act of 2014 (the 2014 Act) was enacted in December 2014. Included in the 2014 Act was a one-year extension of the 50% bonus depreciation. The 2014 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2013. The enacted provisions did not materially impact the Registrants' net income or financial condition but did have a favorable impact on cash flows in 2015.

The Protecting Americans from Tax Hikes Act of 2015 (PATH) included an extension of the 50% bonus depreciation for three years through 2017, phasing down to 40% in 2018 and 30% in 2019. PATH also provided for the extension of research and development, employment and several energy tax credits for 2015. PATH also includes provisions to extend the wind energy production tax credit through 2016 with a three-year phase-out (2017-2019), and to extend the 30% temporary solar investment tax credit for three years through 2019 and with a two-year phase-out (2020-2021). PATH also provided for a permanent extension of the Research and Development tax credit. The enacted provisions did not materially impact the Registrants' net income or financial condition but will have a favorable impact on future cash flows.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. These final regulations did not materially impact the Registrants' net income, cash flows or financial condition.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rate from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012, with the final reduction occurring in years beginning after June 30, 2015. Additional legislation was passed by the state of Indiana reducing the corporate income tax rate from 6.5% in 2016 to 4.9% beginning after June 30, 2016 with the final reduction occurring in years beginning after June 30, 2021. The legislation did not materially impact the Registrants' net income, cash flows or financial condition.

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate was reduced from 7% to 6.5% in 2014. The legislation did not materially impact the Registrants' net income, cash flows or financial condition.

House Bill 32 was passed by the state of Texas in June 2015, permanently reducing the Texas income/franchise tax rate from 0.95% to 0.75% effective January 1, 2016, applicable to reports originally due on or after the effective date. The Texas income/franchise tax rate had been scheduled to return to 1% in 2016. The enacted provision did not materially impact the Registrants' net income, cash flows, or financial condition.

In March 2016, the Texas Comptroller of Public Accounts issued clarifying guidance regarding the treatment of transmission and distribution expenses included in the computation of taxable income for purposes of calculating the Texas income/franchise tax. The guidance clarified which specific transmission and distribution expenses are included in the computation of the cost of goods sold deduction. This guidance resulted in a net favorable adjustment to net income of $21 million, $2 million and $9 million in 2016 for AEP, PSO and SWEPCo, respectively.

In March 2016, Louisiana enacted several tax bills impacting income taxes, franchise taxes and sales taxes. The income tax provisions limit the use of Louisiana net operating losses and the sales tax provisions increase the sales tax rate and suspend or eliminate certain exemptions. The legislation is not expected to materially impact the Registrants' net income, cash flows or financial condition.

13. LEASES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Leases of property, plant and equipment are for remaining periods up to 15 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Year Ended December 31, 2016	AEP		APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Net Lease Expense on Operating Leases	$ 224.9		$ 16.6	$ 90.5	$ 7.1	$ 5.0	$ 6.7
Amortization of Capital Leases	93.7		6.4	35.6	4.2	3.7	13.6
Interest on Capital Leases	18.9		3.5	3.7	0.5	0.6	5.1
Total Lease Rental Costs	$ 337.5		$ 26.5	$ 129.8	$ 11.8	$ 9.3	$ 25.4

Year Ended December 31, 2015	AEP		APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Net Lease Expense on Operating Leases	$ 292.6		$ 16.4	$ 88.3	$ 7.6	$ 5.4	$ 6.7
Amortization of Capital Leases	108.5		5.6	40.7	3.9	3.5	13.7
Interest on Capital Leases	25.1		0.8	3.3	0.6	0.7	6.2
Total Lease Rental Costs	$ 426.2	(a)	$ 22.8	$ 132.3	$ 12.1	$ 9.6	$ 26.6

Year Ended December 31, 2014	AEP		APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Net Lease Expense on Operating Leases	$ 303.9		$ 18.3	$ 93.4	$ 6.6	$ 3.2	$ 5.5
Amortization of Capital Leases	109.4		5.5	44.4	5.7	4.2	14.9
Interest on Capital Leases	26.1		1.0	2.8	1.2	0.7	7.4
Total Lease Rental Costs	$ 439.4	(a)	$ 24.8	$ 140.6	$ 13.5	$ 8.1	$ 27.8

(a) Amounts include lease expenses related to AEPRO that have been classified as Other Operation Expense from Discontinued Operations on the statements of income in the amounts of $89 million and $96 million for the Years Ended December 31, 2015 and 2014, respectively. See “AEPRO (Corporate and Other)” section of Note 7 for additional information.

The following tables show the property, plant and equipment under capital leases and related obligations recorded on the Registrants' balance sheets. Unless shown as a separate line on the balance sheets due to materiality, current capital lease obligations are included in Other Current Liabilities and long-term capital lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the Registrants' balance sheets.

December 31, 2016	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Property, Plant and Equipment Under Capital Leases:						
Generation	$ 146.3	$ 45.0	$ 26.4	$ —	$ 10.0	$ 34.5
Other Property, Plant and Equipment	373.1	18.1	43.7	23.9	19.4	122.1
Total Property, Plant and Equipment	519.4	63.1	70.1	23.9	29.4	156.6
Accumulated Amortization	226.4	18.1	25.4	11.6	15.6	86.5
Net Property, Plant and Equipment Under Capital Leases	$ 293.0	$ 45.0	$ 44.7	$ 12.3	$ 13.8	$ 70.1
Obligations Under Capital Leases:						
Noncurrent Liability	$ 242.1	$ 38.2	$ 35.3	$ 8.1	$ 9.8	$ 65.5
Liability Due Within One Year	63.4	6.8	9.4	4.2	4.1	11.8
Total Obligations Under Capital Leases	$ 305.5	$ 45.0	$ 44.7	$ 12.3	$ 13.9	$ 77.3

December 31, 2015	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Property, Plant and Equipment Under Capital Leases:						
Generation	$ 128.2	$ 43.4	$ 14.5	$ —	$ 9.6	$ 34.5
Other Property, Plant and Equipment	439.3	17.6	68.2	23.4	18.6	165.1
Total Property, Plant and Equipment	567.5	61.0	82.7	23.4	28.2	199.6
Accumulated Amortization	214.1	15.6	19.7	10.2	13.6	91.3
Net Property, Plant and Equipment Under Capital Leases	$ 353.4	$ 45.4	$ 63.0	$ 13.2	$ 14.6	$ 108.3
Obligations Under Capital Leases:						
Noncurrent Liability	$ 247.3	$ 39.1	$ 30.2	$ 9.3	$ 10.9	$ 75.6
Liability Due Within One Year	96.2	6.3	32.8	3.9	3.7	21.9
Total Obligations Under Capital Leases	$ 343.5	$ 45.4	$ 63.0	$ 13.2	$ 14.6	$ 97.5

Future minimum lease payments consisted of the following as of December 31, 2016:

Capital Leases	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
2017	$ 81.3	$ 10.3	$ 15.2	$ 4.7	$ 4.7	$ 14.7
2018	65.0	9.3	9.5	3.8	3.4	13.7
2019	48.7	7.3	5.8	1.5	2.1	12.2
2020	39.3	6.5	5.3	1.1	1.5	10.4
2021	32.8	6.2	5.0	0.9	1.1	9.6
Later Years	118.7	23.7	27.6	1.5	2.6	33.1
Total Future Minimum Lease Payments	385.8	63.3	68.4	13.5	15.4	93.7
Less Estimated Interest Element	80.3	18.3	23.7	1.2	1.5	16.4
Estimated Present Value of Future Minimum Lease Payments	$ 305.5	$ 45.0	$ 44.7	$ 12.3	$ 13.9	$ 77.3

Noncancelable Operating Leases	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
2017	$ 238.2	$ 16.2	$ 91.8	$ 9.3	$ 4.4	$ 6.1
2018	229.5	14.9	90.6	7.9	3.9	5.7
2019	221.0	13.5	89.5	6.4	3.4	5.4
2020	212.7	12.9	86.0	5.4	2.9	5.1
2021	197.6	10.5	81.6	4.5	1.9	4.6
Later Years	282.2	29.0	94.6	18.3	4.6	15.0
Total Future Minimum Lease Payments	$ 1,381.2	$ 97.0	$ 534.1	$ 51.8	$ 21.1	$ 41.9

Master Lease Agreements

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of December 31, 2016, the maximum potential loss by the Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss
	(in millions)
AEP	$ 36.7
APCo	5.4
I&M	3.4
OPCo	5.8
PSO	3.0
SWEPCo	3.5

Rockport Lease (Applies to AEP and I&M)

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2016 are as follows:

Future Minimum Lease Payments	**AEP (a)**	**I&M**
	(in millions)	
2017	$ 147.8	$ 73.9
2018	147.8	73.9
2019	147.8	73.9
2020	147.8	73.9
2021	147.8	73.9
Later Years	147.2	73.6
Total Future Minimum Lease Payments	$ 886.2	$ 443.1

(a) AEP’s future minimum lease payments includes equal shares from AEGCo and I&M.

Railcar Lease (Applies to AEP, I&M and SWEPCo)

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $9 million and $10 million for I&M and SWEPCo, respectively, for the remaining railcars as of December 31, 2016. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from 83% of the projected fair value of the equipment under the current five-year lease term to 77% at the end of the 20-year term. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are $8 million and $10 million for I&M and SWEPCo, respectively, as of December 31, 2016, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

AEPRO Boat and Barge Leases (Applies to AEP)

In October 2015, AEP signed a Purchase and Sale Agreement to sell its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. The sale closed in November 2015. See "AEPRO (Corporate and Other)" section of Note 7. Certain of the boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the lessor, ensuring future payments under such leases with maturities up to 2026. As of December 31, 2016, the maximum potential amount of future payments required under the guaranteed leases was $85 million. In certain instances, AEP has no recourse against the nonaffiliated party if required to pay a lessor under a guarantee, but AEP would have access to sell the leased assets in order to recover payments made by AEP under the guarantee. As of December 31, 2016, AEP's boat and barge lease guarantee liability was $13 million, of which $2 million was recorded in Other Current Liabilities and $11 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheets.

Sabine Dragline Lease (Applies to AEP and SWEPCo)

During 2009, Sabine entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale-and-leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. During 2016, the lease term came to an end and the lease obligation was paid in full. As of December 31, 2015, these capital lease assets were included in Other Property, Plant and Equipment on the balance sheets. The short-term and long-term capital lease obligations were included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheets and in Obligations Under Capital Leases on SWEPCo's balance sheets.

I&M Nuclear Fuel Lease (Applies to AEP and I&M)

In November 2013, I&M entered into a sale-and-leaseback transaction with IMP 11-2013, a nonaffiliated Ohio trust, to lease nuclear fuel for I&M's Cook Plant. In November 2013, I&M sold a portion of its unamortized nuclear fuel inventory to the trust for $110 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 54 months. The future payment obligations of $8 million are included in I&M's future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment on the balance sheets. The short-term capital lease obligations are included in Other Current Liabilities on AEP's balance sheets and in Obligations Under Capital Leases on I&M's balance sheets. The long-term capital lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. The future minimum lease payments for the sale-and-leaseback transaction as of December 31, 2016 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	**I&M**
	(in millions)
2017	$ 5.8
2018	2.4
Total Future Minimum Lease Payments	$ 8.2

14. FINANCING ACTIVITIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Common Stock (Applies to AEP)

Listed below is a reconciliation of common stock share activity:

Shares of AEP Common Stock	Issued	Held in Treasury
Balance, December 31, 2013	508,113,964	20,336,592
Issued	1,625,195	—
Balance, December 31, 2014	509,739,159	20,336,592
Issued	1,650,014	—
Balance, December 31, 2015	511,389,173	20,336,592
Issued	659,347	—
Balance, December 31, 2016	512,048,520	20,336,592

Long-term Debt

The following table details long-term debt outstanding:

Company	Maturity	Weighted Average Interest Rate as of December 31, 2016	Interest Rate Ranges as of December 31, 2016	2015	Outstanding as of December 31, 2016		2015
AEP					(in millions)		
Senior Unsecured Notes	2016-2046	4.90%	1.65%-8.13%	1.65%-8.13%	$ 14,761.0	(e)	$ 13,629.1
Pollution Control Bonds (a)	2016-2042 (b)	2.97%	0.69%-6.30%	0.01%-6.30%	1,725.1		1,784.8
Notes Payable – Nonaffiliated (c)	2016-2032	2.45%	1.456%-6.37%	0.925%-6.60%	326.9		264.7
Securitization Bonds	2016-2031	3.66%	0.88%-5.31%	0.88%-6.25%	1,705.0		2,024.0
Spent Nuclear Fuel Obligation (d)					266.3		265.6
Other Long-term Debt	2016-2059	2.08%	1.15%-13.718%	1.15%-13.718%	1,606.9		1,604.5
Total Long-term Debt Outstanding					$ 20,391.2	(e)	$ 19,572.7
APCo							
Senior Unsecured Notes	2017-2045	5.39%	3.40%-7.00%	3.40%-7.00%	$ 2,972.4		$ 2,970.4
Pollution Control Bonds (a)	2016-2042 (b)	1.96%	0.69%-5.38%	0.01%-5.375%	615.8		616.5
Securitization Bonds	2024-2031	2.91%	2.008%-3.772%	2.008%-3.772%	318.9		341.5
Other Long-term Debt	2019-2026	2.27%	2.06%-13.718%	13.718%	126.8		2.3
Total Long-term Debt Outstanding					$ 4,033.9		$ 3,930.7
I&M							
Senior Unsecured Notes	2019-2046	5.49%	3.20%-7.00%	3.20%-7.00%	$ 1,512.8		$ 1,117.0
Pollution Control Bonds (a)	2016-2025 (b)	2.04%	0.74%-4.625%	0.01%-4.625%	225.4		225.1
Notes Payable – Nonaffiliated (c)	2016-2021	1.63%	1.456%-1.81%	0.925%-2.12%	251.4		175.5
Spent Nuclear Fuel Obligation (d)					266.3		265.6
Other Long-term Debt	2018-2025	2.43%	2.15%-6.00%	1.81%-6.00%	215.5		216.8
Total Long-term Debt Outstanding					$ 2,471.4		$ 2,000.0
OPCo							
Senior Unsecured Notes	2016-2035	5.98%	5.375%-6.60%	5.375%-6.60%	$ 1,590.2		$ 1,938.9
Pollution Control Bonds	2038	5.80%	5.80%	5.80%	32.3		32.2
Securitization Bonds	2018-2020	1.75%	0.958%-2.049%	0.958%-2.049%	140.2		185.3
Other Long-term Debt	2028	1.15%	1.15%	1.15%	1.2		1.3
Total Long-term Debt Outstanding					$ 1,763.9		$ 2,157.7
PSO							
Senior Unsecured Notes	2016-2046	4.80%	3.05%-6.625%	3.17%-6.625%	$ 1,143.2		$ 1,142.7
Pollution Control Bonds (a)	2020	4.45%	4.45%	4.45%	12.6		12.6
Other Long-term Debt	2016-2027	1.96%	1.92%-3.00%	1.587%-3.00%	130.2		130.8
Total Long-term Debt Outstanding					$ 1,286.0		$ 1,286.1
SWEPCo							
Senior Unsecured Notes	2017-2045	4.86%	2.75%-6.45%	3.55%-6.45%	$ 2,359.2		$ 1,961.0
Pollution Control Bonds (a)	2018-2019	3.62%	1.60%-4.95%	1.60%-4.95%	134.9		134.5
Notes Payable – Nonaffiliated (c)	2024-2032	5.17%	4.58%-6.37%	4.58%-6.37%	75.3		78.6
Other Long-term Debt	2017-2023	2.48%	2.346%-4.28%	1.82%	109.7		99.4
Total Long-term Debt Outstanding					$ 2,679.1		$ 2,273.5

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.

(b) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 6).

(e) 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 7 for additional information.

Long-term debt outstanding as of December 31, 2016 is payable as follows:

	AEP		APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2017	$ 3,013.4	(a)	$ 503.1	$ 209.3	$ 46.4	$ 0.5	$ 353.7
2018	1,987.0		194.0	369.3	397.0	0.5	385.4
2019	2,287.1		235.5	518.8	48.0	375.4	457.2
2020	486.4		140.3	10.5	0.1	13.2	3.7
2021	1,308.4		393.0	3.9	500.1	250.5	3.7
After 2021	11,437.3		2,602.0	1,373.7	783.0	653.0	1,491.9
Principal Amount	20,519.6	(a)	4,067.9	2,485.5	1,774.6	1,293.1	2,695.6
Unamortized Discount, Net and Debt Issuance Costs	(128.4)	(a)	(34.0)	(14.1)	(10.7)	(7.1)	(16.5)
Total Long-term Debt Outstanding	$ 20,391.2	(a)	$ 4,033.9	$ 2,471.4	$ 1,763.9	$ 1,286.0	$ 2,679.1

(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 7 for additional information.

In January and February 2017, I&M retired $20 million and $7 million, respectively, of Notes Payable related to DCC Fuel.

In January 2017, APCo retired $104 million of variable rate Pollution Control Bonds due in 2017.

In January 2017, OPCo retired $22 million of Securitization Bonds.

In January 2017, SWEPCo retired $250 million of 5.55% Senior Unsecured Notes due in 2017.

In January 2017, AEP Texas retired $90 million of Securitization Bonds.

In January 2017, AGR retired $500 million of variable rate Other Long-term Debt due in 2017.

In February 2017, APCo retired $12 million of Securitization Bonds.

In February 2017, SWEPCo retired $2 million of Other Long-term Debt.

As of December 31, 2016, trustees held, on behalf of AEP, $614 million of their reacquired Pollution Control Bonds. Of this total, $40 million and $345 million related to I&M and OPCo, respectively.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. 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.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to AGR, APCo and I&M.

Certain AEP subsidiaries also have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the AEP subsidiary distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements.

The most restrictive dividend limitation for certain AEP subsidiaries is through the Federal Power Act restriction, while for other AEP subsidiaries the most restrictive dividend limitation is through the credit agreements. As of December 31, 2016, the maximum amount of restricted net assets of AEP's subsidiaries that may not be distributed to the Parent in the form of a loan, advance or dividend was $10.9 billion.

As of December 31, 2016, the Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. However, the credit agreement covenant restrictions can limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. As of December 31, 2016, the amount of any such restrictions was as follows:

	APCo	I&M	OPCo	PSO	SWEPCo	Other AEP Subsidiaries	AEP
				(in millions)			
Restricted Retained Earnings	$ —	$ 288.5	$ —	$ 127.5	$ 528.9	$ 590.0	$ 1,534.9

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. As of December 31, 2016, AEP had $6.4 billion of available retained earnings to pay dividends to common shareholders. AEP paid $1.1 billion, $1.1 billion and $1 billion of dividends to common shareholders for the years ended December 31, 2016, 2015 and 2014, respectively.

Lines of Credit and Short-term Debt (Applies to AEP)

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 of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2016, AEP had credit facilities totaling $3.5 billion to support its commercial paper program. The maximum amount of commercial paper outstanding during 2016 was $1.5 billion and the weighted average interest rate of commercial paper outstanding during 2016 was 0.80%. AEP's outstanding short-term debt was as follows:

	December 31,			
	2016		2015	
Type of Debt	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
	(in millions)		(in millions)	
Securitized Debt for Receivables (b)	$ 673.0	0.70%	$ 675.0	0.30%
Commercial Paper	1,040.0	1.02%	125.0	0.81%
Total Short-term Debt	$ 1,713.0		$ 800.0	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Corporate Borrowing Program – AEP System (Applies to Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries, and a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of December 31, 2016 and 2015 are included in Advances to Affiliates and Advances from Affiliates, respectively, on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2016:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2016	Authorized Short-term Borrowing Limit
			(in millions)			
APCo	$ 286.9	$ 25.7	$ 148.0	$ 24.8	$ (55.5)	$ 600.0
I&M	369.1	97.6	129.9	19.5	(202.7)	500.0
OPCo	227.9	379.2	116.6	182.4	24.2	400.0
PSO	52.0	205.4	12.9	48.1	(52.0)	300.0
SWEPCo	249.4	313.3	171.8	267.7	167.8	350.0

Year Ended December 31, 2015:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2015	Authorized Short-term Borrowing Limit
			(in millions)			
APCo	$ 211.2	$ 694.8	$ 82.0	$ 79.0	$ (155.4)	$ 600.0
I&M	297.3	13.5	152.6	13.5	(282.6)	500.0
OPCo	—	367.5	—	266.6	331.1	400.0
PSO	165.9	152.5	113.1	86.8	80.6	300.0
SWEPCo	112.5	299.9	48.1	103.4	(58.3)	350.0

The activity in the above tables does not include short-term lending activity of SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC, which is a participant in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of December 31, 2016 are included in Advances to Affiliates on SWEPCo's balance sheets. For the year ended December 31, 2016, Mutual Energy SWEPCo, LLC had the following activity in the Nonutility Money Pool:

Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2016
	(in millions)	
$ 2.0	$ 2.0	$ 2.0

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Years Ended December 31,		
	2016	2015	2014
Maximum Interest Rate	1.02%	0.87%	0.59%
Minimum Interest Rate	0.69%	0.37%	0.24%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Years Ended December 31,			Average Interest Rate for Funds Loaned to the Utility Money Pool for Years Ended December 31,		
Company	2016	2015	2014	2016	2015	2014
APCo	0.80%	0.53%	0.29%	0.82%	0.47%	0.29%
I&M	0.80%	0.49%	0.31%	0.80%	0.48%	0.30%
OPCo	0.85%	—%	0.27%	0.74%	0.48%	0.34%
PSO	0.96%	0.49%	0.29%	0.83%	0.48%	—%
SWEPCo	0.79%	0.53%	0.29%	0.90%	0.48%	0.32%

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool are summarized for Mutual Energy SWEPCo, LLC in the following table:

Year Ended December 31,	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
2016	1.02%	0.69%	0.82%

Interest expense related to short-term borrowing activities with the Utility Money Pool is included in Interest Expense on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries incurred interest expense for all short-term borrowing activities as follows:

	Years Ended December 31,		
Company	2016	2015	2014
		(in millions)	
APCo	$ 1.2	$ 0.2	$ —
I&M	0.9	0.8	0.1
OPCo	0.4	—	—
PSO	—	0.1	0.3
SWEPCo	1.0	0.1	0.2

Interest income related to short-term lending activities with the Utility Money Pool is included in Interest Income on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries earned interest income for all short-term lending activities as follows:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
APCo	$ 0.2	$ 0.4	$ 0.3
I&M	0.2	0.1	0.1
OPCo	0.9	1.3	0.2
PSO	0.4	0.4	—
SWEPCo	0.6	0.4	—

Interest expense and interest income related to the Nonutility Money Pool are included in Interest Expense and Interest Income, respectively, on SWEPCo's statements of income. For amounts borrowed from and advanced to the Nonutility Money Pool, SWEPCo incurred $16 thousand of interest income for the year ended December 31, 2016.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 6.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables and accelerate AEP Credit's cash collections.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables. The agreement was increased in June 2014 from $700 million and expires in June 2018.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2016	2015	2014
		(dollars in millions)	
Effective Interest Rates on Securitization of Accounts Receivable	0.70%	0.30%	0.22%
Net Uncollectible Accounts Receivable Written Off	$ 23.7	$ 34.1	$ 40.1

	December 31, 2016	2015
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 945.0	$ 924.8
Short-term – Securitized Debt of Receivables	673.0	675.0
Delinquent Securitized Accounts Receivable	42.7	48.3
Bad Debt Reserves Related to Securitization	27.7	17.5
Unbilled Receivables Related to Securitization	322.1	357.8

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to Registrant Subsidiaries)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary was as follows:

Company	December 31, 2016	December 31, 2015
	(in millions)	
APCo	$ 142.0	$ 135.4
I&M	136.7	134.8
OPCo	388.3	351.4
PSO	110.4	116.1
SWEPCo	130.9	151.8

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
APCo	$ 6.7	$ 7.6	$ 8.9
I&M	7.1	8.4	7.9
OPCo	28.9	30.7	28.8
PSO	6.2	5.8	5.9
SWEPCo	6.9	7.0	6.8

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
APCo	$ 1,412.5	$ 1,453.8	$ 1,519.3
I&M	1,596.2	1,553.0	1,488.6
OPCo	2,633.0	2,569.4	2,647.6
PSO	1,269.3	1,326.1	1,321.1
SWEPCo	1,531.7	1,597.8	1,655.8

15. STOCK-BASED COMPENSATION

The disclosures in this note apply to AEP only. The impact of AEP's share-based compensation plans is insignificant to the financial statements of the Registrant Subsidiaries.

AEP's long-term incentive plan available for eligible employees and directors, the Amended and Restated American Electric Power System Long-Term Incentive Plan (the "Prior Plan"), was replaced prospectively for new grants by the American Electric Power System 2015 Long-Term Incentive Plan (the "2015 LTIP") effective in April 2015. The 2015 LTIP provides for a maximum of 10 million common shares to be available for grant to eligible employees and directors. As of December 31, 2016, 9,822,644 shares remained available for issuance under the 2015 LTIP plan. No new awards may be granted under the Prior Plan. To the extent the issuance of a share that is subject to an outstanding award under the Prior Plan, the issuance of that share will take place under the Prior Plan. The 2015 LTIP awards may be stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance share units, cash-based awards and other stock-based awards. If a share is issued pursuant to a stock option or a stock appreciation right, it will reduce the aggregate amount authorized under the 2015 LTIP by 0.286 of a share. If a share is issued for any other award that settles in AEP stock, it will reduce the aggregate amount authorized under the 2015 LTIP by one share. Cash settled awards do not reduce the aggregate amount authorized under the 2015 LTIP. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of AEP's Board of Directors (HR Committee).

Performance Units

AEP's performance units are paid out in cash rather than AEP shares and do not reduce the aggregate share authorization. AEP's performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. The number of performance units held at the end of the three year performance period is multiplied by the performance score to determine the actual number of performance units realized. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee. Certain employees must satisfy stock ownership requirements. If those employees have not met their stock ownership requirements, a portion or all of their performance units are mandatorily deferred as AEP career shares to the extent needed to meet their stock ownership requirement. AEP career shares are a form of non-qualified deferred compensation that has a value equivalent to shares of AEP common stock. AEP career shares are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP career shares accrue as additional units. Management records compensation cost for performance units over a three-year vesting period. The liability for both the performance units and AEP career shares, recorded in Employee Benefits and Pension Obligations on the balance sheets, is adjusted for changes in value.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP career shares for the years ended December 31, 2016, 2015 and 2014 as follows:

Performance Units	Years Ended December 31, 2016	2015	2014
Awarded Units (in thousands)	597.4	575.0	16.9
Weighted Average Unit Fair Value at Grant Date	$ 62.77	$ 59.19	$ 49.73
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2016	2015	2014
Awarded Units (in thousands)	89.2	103.6	98.9
Weighted Average Fair Value at Grant Date	$ 63.83	$ 54.35	$ 53.35
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP career shares vest immediately when the dividend is awarded but are not paid in cash until after the participant's AEP employment ends.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The performance scores for all performance periods were dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the Standard and Poor's 500 Electric Utilities Index and (b) three-year cumulative earnings per share measured relative to a target approved by AEP's Board of Directors.

The certified performance scores and units earned for the three-year periods ended December 31, 2016, 2015 and 2014 were as follows:

Performance Units	Years Ended December 31, 2016	2015	2014
Certified Performance Score	163.9%	176.3%	147.8%
Performance Units Earned	1,111,966	1,202,107	889,697
Performance Units Mandatorily Deferred as AEP Career Shares	9,963	41,707	40,831
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	51,684	54,074	39,526
Performance Units to be Paid in Cash	1,050,319	1,106,326	809,340

The cash payouts for the years ended December 31, 2016, 2015 and 2014 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2016	2015	2014
		(in millions)	
Cash Payouts for Performance Units	$ 62.7	$ 48.1	$ 29.3
Cash Payouts for AEP Career Share Distributions	9.1	3.0	4.3

Restricted Stock Units

The HR Committee grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. The RSUs accrue dividends as additional RSUs. The additional RSUs granted as dividends vest on the same date as the underlying RSUs. RSUs are converted into a share of AEP common stock upon vesting, except for AEP's officers subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934, who are paid in cash. In 2014, there were no RSUs granted to Section 16 officers due to a change that deferred granting these and other awards until February 2015. For RSUs paid in shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of RSUs granted by the grant date market closing price. For RSUs paid in cash, compensation cost is recorded over the vesting period and adjusted for changes in fair value until vested. The fair value at vesting is determined by multiplying the number of RSUs vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is approximately 40 months from the grant date.

In 2010, the HR Committee granted a total of 165,520 RSUs to four Chief Executive Officer succession candidates as a retention incentive for these candidates. These grants vested in three approximately equal installments in August 2013, August 2014 and August 2015.

The HR Committee awarded RSUs, including additional units awarded as dividends, for the years ended December 31, 2016, 2015 and 2014 as follows:

Restricted Stock Units	Years Ended December 31, 2016	2015	2014
Awarded Units (in thousands)	242.0	397.5	64.1
Weighted Average Grant Date Fair Value	$ 62.88	$ 58.56	$ 50.36

The total fair value and total intrinsic value of restricted stock units vested during the years ended December 31, 2016, 2015 and 2014 were as follows:

Restricted Stock Units	Years Ended December 31, 2016	2015	2014
		(in millions)	
Fair Value of Restricted Stock Units Vested	$ 16.4	$ 18.3	$ 18.7
Intrinsic Value of Restricted Stock Units Vested (a)	21.0	24.2	24.9

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of AEP's nonvested RSUs as of December 31, 2016 and changes during the year ended December 31, 2016 are as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2016	721.3	$ 52.48
Granted	242.0	62.88
Vested	(326.7)	50.07
Forfeited	(33.0)	55.81
Nonvested as of December 31, 2016	603.6	57.54

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2016 was $38 million and the weighted average remaining contractual life was 1.7 years.

Other Stock-Based Plans

AEP also has a Stock Unit Accumulation Plan for Non-Employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to Non-Employee Directors are fully vested upon grant date. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date. After five years of service on the Board of Directors, non-employee directors receive contributions to an AEP stock fund awarded under the Stock Unit Accumulation Plan. Such amounts may be exchanged into other market-based investments that are similar to the investment options available to employees that participate in AEP's Incentive Compensation Deferral Plan.

Management records compensation cost for stock units when the units are awarded and adjusts the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

The cash payouts for stock unit distributions for the years ended December 31, 2016, 2015 and 2014 were $0 million, $1 million and $5 million, respectively.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2016, 2015 and 2014 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2016	2015	2014
Awarded Units (in thousands)	19.1	24.9	25.4
Weighted Average Grant Date Fair Value	$ 64.96	$ 55.46	$ 54.08

Share-based Compensation Plans

Compensation cost for share-based payment arrangements, the actual tax benefit realized from the tax deductions for compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2016, 2015 and 2014 were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2016**	**2015**	**2014**
		(in millions)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 66.5	$ 63.8	$ 85.4
Actual Tax Benefit Realized	23.3	22.3	29.9
Total Compensation Cost Capitalized	20.8	20.3	23.1

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

During the years ended December 31, 2016, 2015 and 2014, there were no significant modifications affecting any of AEP's share-based payment arrangements.

As of December 31, 2016, there was $62 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the 2015 LTIP and Prior Plan. Unrecognized compensation cost related to unvested share-based arrangements will change as the fair value of performance units and AEP career shares is adjusted each period and as forfeitures for all award types are realized. AEP's unrecognized compensation cost will be recognized over a weighted-average period of 1.37 years.

AEP's practice prior to August 2016 was to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. In August 2016, AEP began also using shares purchased on the open market to fulfill such share commitments. AEP is permitted to use treasury shares, shares acquired in the open market specifically for distribution under the 2015 LTIP and Prior Plan or any combination thereof for this purpose. Management anticipates using a combination of open market purchases and treasury shares for this purpose going forward. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset AEP's tax withholding obligation.

16. RELATED PARTY TRANSACTIONS

The disclosures in this note apply to all Registrant Subsidiaries unless indicated otherwise.

For other related party transactions, also see “AEP System Tax Allocation Agreement” section of Note 12 in addition to “Utility Money Pool – AEP System” and “Sale of Receivables – AEP Credit” sections of Note 14.

Interconnection Agreement

In accordance with management’s December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

APCo, I&M, KPCo, OPCo and AEPSC were parties to the Interconnection Agreement which defined the sharing of costs and benefits associated with the respective generation plants. This sharing was based upon each AEP utility subsidiary’s MLR and was calculated monthly on the basis of each AEP utility subsidiary’s maximum peak demand in relation to the sum of the maximum peak demands of all four AEP utility subsidiaries during the preceding 12 months.

Effective January 1, 2014, the FERC approved the following agreements.

- A Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants’ respective power supply resources. Effective May 2015, the PCA was revised and approved by the FERC to include WPCo. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. Further, the Restated and Amended PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.
- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies would fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR committed to use its capacity to help meet the PJM capacity obligations of member companies through the PJM planning year that ended May 31, 2015.
- A Power Supply Agreement (PSA) between AGR and OPCo that provided for AGR to supply capacity for OPCo’s switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo’s non-switched retail load that was not acquired through auctions in 2014.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Effective January 1, 2014 and revised in May 2015, power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies’ respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. Effective January 1, 2014 and with the transfer of OPCo’s generation assets to AGR, AEPSC conducts only gasoline, diesel fuel, energy procurement and risk management activities on OPCo’s behalf.

Operating Agreement (Applies to PSO and SWEPCo)

PSO, SWEPCo and AEPSC are parties to the Operating Agreement which was approved by the FERC. The Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. In January 2014, the FERC approved a modification of the Operating Agreement to address changes resulting from an anticipated March 2014 SPP power market change. Subsequently and in March 2014, SPP changed from an energy imbalance service market to a fully integrated power market. In alignment with the new SPP integrated power market and according to the modified Operating Agreement, PSO and SWEPCo operate as standalone entities and offer their respective generation into the SPP power market. SPP then economically dispatches resources. By offering their resources separately, PSO and SWEPCo no longer purchase or sell energy to each other to serve their respective internal load or off-system sales.

System Integration Agreement (SIA) (Applies to APCo, I&M, PSO and SWEPCo)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM and MISO generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

The following tables show the revenues derived from sales under the Interconnection Agreement, direct sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2016, 2015 and 2014:

Related Party Revenues	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)		
Year Ended December 31, 2016					
Direct Sales to East Affiliates	$ 126.0	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	3.7
Auction Sales to OPCo (a)	9.2	12.0	—	—	—
Direct Sales to AEPEP	—	—	—	—	(0.2)
Transmission Agreement and Transmission Coordination Agreement Sales	1.3	12.2	(2.0)	(1.7)	19.4
Other Revenues	5.6	2.0	19.3	4.3	1.6
Total Affiliated Revenues	$ 142.1	$ 26.2	$ 17.3	$ 2.6	$ 24.5

Related Party Revenues	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)		
Year Ended December 31, 2015					
Direct Sales to East Affiliates	$ 132.1	$ —	$ —	$ —	$ —
Auction Sales to OPCo (a)	10.6	17.1	—	—	—
Direct Sales to AEPEP	—	—	29.7	—	(0.2)
Transmission Agreement and Transmission Coordination Agreement Sales	0.7	8.4	35.5	0.2	15.2
Other Revenues	4.4	1.9	18.9	4.4	1.6
Total Affiliated Revenues	$ 147.8	$ 27.4	$ 84.1	$ 4.6	$ 16.6

Related Party Revenues	APCo	I&M	OPCo (in millions)	PSO	SWEPCo
Year Ended December 31, 2014					
Sales under Interconnection Agreement (b)	$ 0.2	$ 0.5	$ 1.1	$ —	$ —
Direct Sales to East Affiliates	141.7	—	—	3.8	10.1
Direct Sales to West Affiliates	0.6	0.4	—	—	0.3
Direct Sales to AEPEP	—	—	44.1	—	—
Transmission Agreement and Transmission Coordination Agreement Sales	(1.6)	1.7	104.1	—	14.1
Other Revenues	3.6	1.6	15.9	3.3	1.8
Total Affiliated Revenues	$ 144.5	$ 4.2	$ 165.2	$ 7.1	$ 26.3

(a) Refer to the Ohio Auctions section below for further information regarding these amounts.
(b) Includes December 2013 true-up activity subsequent to agreement termination.

The following tables show the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2016, 2015 and 2014:

Related Party Purchases	APCo	I&M	OPCo (in millions)	PSO	SWEPCo
Year Ended December 31, 2016					
Direct Purchases from West Affiliates	—	—	—	3.7	—
Auction Purchases from AEPEP (a)	—	—	110.1	—	—
Auction Purchases from AEP Energy (a)	—	—	7.7	—	—
Auction Purchases from AEPSC (a)	—	—	24.1	—	—
Direct Purchases from AEGCo	—	228.6	—	—	—
Total Affiliated Purchases	$ —	$ 228.6	$ 141.9	$ 3.7	$ —

Related Party Purchases	APCo	I&M	OPCo (in millions)	PSO	SWEPCo
Year Ended December 31, 2015					
Direct Purchases from AGR(c)	$ —	$ —	$ 269.2	$ —	$ —
Auction Purchases from AEPEP (a)	—	—	225.2	—	—
Auction Purchases from AEPSC (a)	—	—	32.7	—	—
Direct Purchases from AEGCo	—	232.1	—	—	—
Total Affiliated Purchases	$ —	$ 232.1	$ 527.1	$ —	$ —

Related Party Purchases	APCo	I&M	OPCo (in millions)	PSO	SWEPCo
Year Ended December 31, 2014					
Purchases under Interconnection Agreement (b)	$ 4.7	$ 1.6	$ 0.1	$ —	$ —
Direct Purchases from East Affiliates	—	—	—	1.0	—
Direct Purchases from West Affiliates	—	—	—	10.0	3.8
Direct Purchases from AGR(c)	—	—	1,305.2	—	—
Direct Purchases from AEPEP	—	—	44.4	—	—
Direct Purchases from AEGCo	—	268.4	—	—	—
Total Affiliated Purchases	$ 4.7	$ 270.0	$ 1,349.7	$ 11.0	$ 3.8

(a) Refer to the Ohio Auctions section below for further information regarding this amount.
(b) Includes December 2013 true-up activity subsequent to agreement termination.
(c) Amounts exclude $31 million and $157 million in 2015 and 2014, respectively, which are now presented as Generation Deferrals on the Statement of Income.

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates, respectively, on the Registrant Subsidiaries' statements of income. Since the Registrant Subsidiaries are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

System Transmission Integration Agreement (STIA)

AEP's STIA provided for the integration and coordination of the planning, operation and maintenance of transmission facilities. Since the FERC approved the cancellation of the STIA effective June 1, 2014, the coordinated planning, operation and maintenance of transmission facilities are the responsibility of the RTOs and the STIA is no longer necessary. Similar to the SIA, the STIA functioned as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The TA and TCA are both still active. The STIA contained two service schedules that governed:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

APCo, I&M, KGPCo, KPCo, OPCo and WPCo are parties to the TA, effective November 2010, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies, KGPCo and WPCo on a 12-month average coincident peak basis.

The following table shows the net charges recorded by the Registrant Subsidiaries for the years ended December 31, 2016, 2015 and 2014 related to the TA:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
APCo	$ 103.2	$ 92.7	$ 84.7
I&M	53.0	38.0	39.7
OPCo	143.6	81.0	17.0

The charges shown above are recorded in Other Operation expenses on the statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such a tariff.

Under the TCA, the parties to the agreement delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP.

The following table shows the net (revenues) expenses allocated among parties to the TCA pursuant to the SPP OATT protocols as described above for the years ended December 31, 2016, 2015 and 2014:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
PSO	$ 19.6	$ 15.0	$ 14.1
SWEPCo	(19.6)	(15.0)	(14.1)

The net (revenues) expenses shown above are recorded in Sales to AEP Affiliates on SWEPCo's statements of income and Other Operation expenses on PSO's statements of income.

Ohio Auctions (Applies to APCo, I&M and OPCo)

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy, AEPEP, APCo, KPCo, I&M and WPCo participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions. See Note 10 - Derivatives and Hedging for further information.

Unit Power Agreements (UPA) (Applies to I&M)

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

Cook Coal Terminal (Applies to I&M, PSO and SWEPCo)

Cook Coal Terminal, which is owned by AEGCo, performs coal transloading and storage services at cost for I&M. The coal transloading expenses in 2016, 2015 and 2014 were as follows:

	Years Ended December 31,		
Company	**2016**	**2015**	**2014**
		(in millions)	
I&M	$ 12.8	$ 15.8	$ 16.2

I&M recorded the cost of transloading services in Fuel on the balance sheet.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M, PSO and SWEPCo. The railcar maintenance revenues in 2016, 2015 and 2014 were as follows:

	Years Ended December 31,		
Company	**2016**	**2015**	**2014**
		(in millions)	
I&M	$ 1.7	$ 2.0	$ 2.5
PSO	0.6	0.2	0.3
SWEPCo	3.3	2.8	3.3

I&M, PSO and SWEPCo recorded the cost of the railcar maintenance services in Fuel on the balance sheets.

I&M Barging, Urea Transloading and Other Services (Applies to APCo and I&M)

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
AEGCo	$ 14.8	$ 16.1	$ 22.7
AGR	0.3	4.9	5.2
APCo	36.9	37.7	36.1
KPCo	5.3	4.6	5.0
WPCo	4.8	—	—
AEP River Operations LLC – (Nonutility Subsidiary of AEP)	—	15.5	25.3

Services Provided by AEP River Operations LLC (Applies to I&M)

AEP River Operations LLC provided services for barge towing, chartering and general and administrative expenses to I&M. The costs are recorded by I&M as Other Operation expenses. In October 2015, AEP signed a Purchase and Sale Agreement to sell AEP River Operations LLC to a nonaffiliated party. The sale closed in November 2015. For the years ended December 31, 2015 and 2014, I&M recorded expenses of $19 million and $24 million, respectively, for these activities.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. The AEP subsidiaries recorded these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the following affiliates:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
AEGCo	$ —	$ 0.1	$ 0.1
AGR	2.0	2.7	2.8
I&M	2.9	2.5	1.7
KPCo	1.5	1.3	1.2
PSO	0.5	0.2	0.3
SWEPCo	0.9	0.8	0.1

Affiliate Railcar Agreement (Applies to APCo, I&M, PSO and SWEPCo)

Certain AEP subsidiaries have an agreement providing for the use of each other's leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. The AEP subsidiaries recorded these costs or reimbursements as costs or reduction of costs, respectively, in Fuel on the balance sheets and such costs are recoverable from customers. The following tables show the net effect of the railcar agreement on the balance sheets:

	December 31, 2016 Billing Company		
Billed Company	**I&M**	**PSO**	**SWEPCo**
APCo	$ —	$ 0.3	$ 0.3
I&M	—	0.3	0.8
PSO	0.3	—	0.2
SWEPCo	0.9	0.3	—

	December 31, 2015 Billing Company		
Billed Company	**I&M**	**PSO**	**SWEPCo**
APCo	$ —	$ 0.3	$ 0.3
I&M	—	0.4	1.2
PSO	0.6	—	0.6
SWEPCo	1.8	0.6	—

OVEC (Applies to APCo, I&M and OPCo)

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2016, the ownership and investment in OVEC were as follows:

	December 31, 2016	
Company	**Ownership**	**Investment (in millions)**
Parent	39.17%	$ 4.0
OPCo	4.30%	0.4
Total	43.47%	$ 4.4

OVEC's owners, along with APCo and I&M, are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries, including APCo, I&M and OPCo, is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2016, OVEC's outstanding indebtedness is approximately $1.5 billion. The Registrants' are responsible for their 43.47% share of OVEC's outstanding debt. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6.

Purchased Power from OVEC

The amounts of power purchased by the Registrant Subsidiaries from OVEC for the years ended December 31, 2016, 2015 and 2014 were:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
APCo	$ 88.0	$ 87.2	$ 96.9
I&M	44.0	43.7	48.5
OPCo	111.7	110.8	123.1

The amounts above are included in Purchased Electricity for Resale on the statements of income.

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following tables show the sales and purchases, recorded at net book value, for the years ended December 31, 2016, 2015 and 2014:

Sales

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
APCo	$ 4.5	$ 9.4	$ 3.0
I&M	5.2	3.0	1.3
OPCo	1.9	2.4	0.5
PSO	7.5	7.1	0.5
SWEPCo	1.0	0.8	1.2

Purchases

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
APCo	$ 1.5	$ 8.6	$ 0.9
I&M	2.7	8.1	1.4
OPCo	1.7	2.1	1.9
PSO	3.2	0.6	2.1
SWEPCo	6.5	7.4	4.0

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

17. VARIABLE INTEREST ENTITIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities". In determining whether AEP is the primary beneficiary of a VIE, management considers whether AEP has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently.

AEP is the primary beneficiary of Sabine, DCC Fuel, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, AEP Credit, a protected cell of EIS, Transource Energy and AEP Renewables. In addition, AEP has not provided material financial or other support to any of these entities that was not previously contractually required. AEP holds a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Consolidated Variable Interests Entities

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2016, 2015 and 2014 were $162 million, $152 million and $151 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2016, 2015 and 2014 were $101 million, $115 million and $109 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that AEP Texas is the primary beneficiary of Transition Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Transition Funding. The securitized bonds totaled $1.2 billion and $1.5 billion as of December 31, 2016 and 2015, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Transition

Funding has securitized transition assets of $1.1 billion and $1.3 billion as of December 31, 2016 and 2015, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from AEP Texas under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $140 million and $185 million as of December 31, 2016 and 2015, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $62 million and $86 million as of December 31, 2016 and 2015, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on OPCo's balance sheets.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $319 million and $342 million as of December 31, 2016 and 2015, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $305 million and $328 million as of December 31, 2016 and 2015, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's balance sheets.

AEP Credit is a wholly-owned subsidiary of Parent. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on AEP's control of AEP Credit, management concluded that AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Sale of Receivables - AEP Credit" section of Note 14.

AEP's subsidiaries participate in one protected cell of EIS for approximately eight lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. AEP's subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the years ended December 31, 2016, 2015 and 2014 were $28 million, $29 million and $32 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. In January 2014, Transource Missouri (a wholly-owned subsidiary of Transource Energy) acquired transmission assets from the non-controlling owner and issued debt and received a capital contribution to fund the acquisition. The majority of Transource Energy's activity resulted from the asset acquisition, construction projects, debt issuance and capital contribution. AEP has provided capital contributions to Transource Energy of $45 million and $47 million, in 2016 and 2015, respectively. AEP and the other owner of Transource Energy are required to ensure a specific equity level in Transource Missouri upon completion of projects or if a project is abandoned by the RTO. See the tables below for the classification of Transource Energy's assets and liabilities on the balance sheets.

AEP Renewables, a wholly-owned subsidiary of Energy Supply, was formed to provide utility scale wind and solar projects whose power output is sold via long-term power purchase agreements to other utilities, cities and corporations. In the third and fourth quarters of 2016, AEP Renewables acquired Pavant Solar III, LLC and Boulder Solar II, LLC, respectively. AEP Renewables has not received a capital contribution to date from their parent company, but has participated in the AEP corporate borrowing program to fund the aforementioned projects. Management has concluded that AEP Renewables is a VIE and that Energy Supply is the primary beneficiary because Energy Supply has the power to direct the most significant activities of the entity and Energy Supply's equity interest could potentially be significant. See the tables below for the classification of AEP Renewables' assets and liabilities on the balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2016

	Registrant Subsidiaries						
	SWEPCo Sabine	I&M DCC Fuel	OPCo Ohio Phase-in-Recovery Funding		APCo Appalachian Consumer Rate Relief Funding	
	(in millions)					
ASSETS						
Current Assets	$ 60.2	$ 135.5	$ 30.3		$ 20.2	
Net Property, Plant and Equipment	112.0	233.9	—		—	
Other Noncurrent Assets	89.8	116.2	117.1	(a)	309.0	(b)
Total Assets	$ 262.0	$ 485.6	$ 147.4		$ 329.2	
LIABILITIES AND EQUITY						
Current Liabilities	$ 26.3	$ 131.3	$ 47.5		$ 27.3	
Noncurrent Liabilities	235.3	354.3	98.6		300.6	
Equity	0.4	—	1.3		1.3	
Total Liabilities and Equity	$ 262.0	$ 485.6	$ 147.4		$ 329.2	

(a) Includes an intercompany item eliminated in consolidation of $55 million.
(b) Includes an intercompany item eliminated in consolidation of $3.7 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2016

	Other Consolidated VIEs					
	AEP Credit	AEP Texas Transition Funding		Protected Cell of EIS	Transource Energy	AEP Renewables
	(in millions)					
ASSETS						
Current Assets	$ 945.7	$ 184.8		$ 170.6	$ 16.3	$ —
Net Property, Plant and Equipment	—	—		—	313.0	130.4
Other Noncurrent Assets	10.3	1,149.4	(a)	1.1	5.4	9.0
Total Assets	$ 956.0	$ 1,334.2		$ 171.7	$ 334.7	$ 139.4
LIABILITIES AND EQUITY						
Current Liabilities	$ 877.4	$ 251.9		$ 31.8	$ 31.7	$ 126.7
Noncurrent Liabilities	0.6	1,064.2		97.3	134.4	11.3
Equity	78.0	18.1		42.6	168.6	1.4
Total Liabilities and Equity	$ 956.0	$ 1,334.2		$ 171.7	$ 334.7	$ 139.4

(a) Includes an intercompany item eliminated in consolidation of $61.1 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2015

	Registrant Subsidiaries			
	SWEPCo Sabine	I&M DCC Fuel	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding
	(in millions)			
ASSETS				
Current Assets	$ 61.7	$ 91.1	$ 31.2	$ 18.5
Net Property, Plant and Equipment	147.0	159.9	—	—
Other Noncurrent Assets	61.8	84.6	162.0 (a)	332.0 (b)
Total Assets	$ 270.5	$ 335.6	$ 193.2	$ 350.5
LIABILITIES AND EQUITY				
Current Liabilities	$ 47.7	$ 84.8	$ 47.3	$ 27.1
Noncurrent Liabilities	222.3	250.8	144.6	321.5
Equity	0.5	—	1.3	1.9
Total Liabilities and Equity	$ 270.5	$ 335.6	$ 193.2	$ 350.5

(a) Includes an intercompany item eliminated in consolidation of $76.1 million.
(b) Includes an intercompany item eliminated in consolidation of $4 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2015

	Other Consolidated VIEs			
	AEP Credit	AEP Texas Transition Funding	Protected Cell of EIS	Transource Energy
	(in millions)			
ASSETS				
Current Assets	$ 925.7	$ 234.1	$ 165.3	$ 10.8
Net Property, Plant and Equipment	—	—	—	227.2
Other Noncurrent Assets	6.4	1,365.7 (a)	1.9	5.5
Total Assets	$ 932.1	$ 1,599.8	$ 167.2	$ 243.5
LIABILITIES AND EQUITY				
Current Liabilities	$ 855.1	$ 291.7	$ 41.8	$ 36.6
Noncurrent Liabilities	0.3	1,290.0	83.9	113.0
Equity	76.7	18.1	41.5	93.9
Total Liabilities and Equity	$ 932.1	$ 1,599.8	$ 167.2	$ 243.5

(a) Includes an intercompany item eliminated in consolidation of $68.2 million.

Non-Consolidated Significant Variable Interests

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2016, 2015 and 2014 were \$65 million, \$93 million and \$56 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31,			
	2016		2015	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 7.6	$ 7.6	$ 7.6	$ 7.6
Retained Earnings	15.7	15.7	7.7	7.7
SWEPCo's Guarantee of Debt	—	91.3	—	82.9
Total Investment in DHLC	$ 23.3	$ 114.6	$ 15.3	$ 98.2

AEP and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. AEP has no interest or control in the "Allegheny Series". AEP is not required to consolidate PATH-WV as AEP is not the primary beneficiary, although AEP holds a significant variable interest in PATH-WV. AEP's equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. AEP and FirstEnergy share the returns and losses equally in PATH-WV. AEP's subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, the transmission project that PATH was intended to develop and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The parties to the case were unable to reach a settlement agreement and in March 2014, settlement judge procedures were terminated. Hearings at the FERC were held in March and April 2015. In April 2015, PATH filed a stipulation agreement with the FERC that agreed to a 50% debt and 50% equity capital structure and a 4.7% cost of long-term debt for the entire amortization period. In September 2015, the Administrative Law Judge (ALJ) issued an advisory Initial Decision. Additional briefing was submitted during the fourth quarter of 2015. In January 2017, the FERC issued its order on Initial Decision, adopting in part and rejecting in part the ALJ's recommendations. The FERC order included (a) a finding that the PATH Project's abandonment costs were prudently incurred, (b) a finding that the disposition of certain assets was prudent, (c) guidance regarding the future disposition of assets, (d) a reduction of PATH WV's authorized return on equity (ROE) to 8.11% prospectively only after the date of the order, (e) an adjustment of the amortization period to end December 2017, and (f) a credit for certain amounts that were deemed to be not includable in PATH-WV's formula rates.

In February 2017, the PATH Companies filed a request for rehearing of two adverse rulings in the January 2017 FERC order. The request seeks the FERC to reverse its reduction of the PATH Companies 10.4% ROE for the period after January 19, 2017 and to allow the recovery of certain education and outreach costs disallowed by the order as being required to be recorded in accounts not recoverable under the PATH Companies' formula rates. The PATH Companies may appeal an adverse order by the FERC once it issues an order on the merits of the PATH Companies' request for rehearing. In February 2017, the Edison Electric Institute ("EEI") also filed a request for rehearing recommending reversal of the January 2017 FERC ordered ROE reduction and cost disallowance. The requests for rehearing by the PATH Companies and EEI are currently pending before the FERC. The requests for rehearing do not impact either the timing of the compliance filing required by the order, to be filed in March 2017, or the recovery of costs by the PATH Companies under their formula rates. Depending on the resolution of these proceedings and annual true-ups under their formula rate, the PATH Companies may be required to refund amounts recovered under their formula rates. Management believes its financial statements adequately provide for the outcome of these proceedings.

AEP's investment in PATH-WV was:

	December 31,			
	2016		2015	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from Parent	$ 18.8	$ 18.8	$ 18.8	$ 18.8
Retained Earnings	(2.3)	(2.3)	2.2	2.2
Total Investment in PATH-WV	$ 16.5	$ 16.5	$ 21.0	$ 21.0

As of December 31, 2016, AEP's $16.5 million investment in PATH-WV was included in Deferred Charges and Other Noncurrent Assets on the balance sheet. If AEP cannot ultimately recover the investment related to PATH-WV, it could reduce future net income and cash flows.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Years Ended December 31,		
Company	**2016**	**2015**	**2014**
		(in millions)	
APCo	$ 244.2	$ 227.5	$ 216.5
I&M	147.7	139.5	133.2
OPCo	181.1	177.8	169.0
PSO	111.0	107.3	101.4
SWEPCo	147.0	141.4	140.3

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

	December 31,			
	2016		2015	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
APCo	$ 36.7	$ 36.7	$ 25.8	$ 25.8
I&M	24.2	24.2	16.6	16.6
OPCo	28.1	28.1	23.3	23.3
PSO	16.0	16.0	12.6	12.6
SWEPCo	21.8	21.8	16.4	16.4

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1, leases a 50% interest in Rockport Plant, Unit 2 and owned 100% of the Lawrenceburg Generating Station, which was sold in January 2017. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEGCo has a Unit Power Agreement associated with the Lawrenceburg Generating Station which was assigned by OPCo to AGR effective January 1, 2014. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. Total billings to I&M from AEGCo for the years ended December 31, 2016, 2015 and 2014 were $229 million, $232 million and $268 million. The carrying amount of I&M's liabilities associated with AEGCo as of December 31, 2016 and 2015 was $22 million and $17 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 13. The assets and liabilities of AEGCo's Lawrenceburg Plant 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 7 for additional information.

18. PROPERTY, PLANT AND EQUIPMENT

The disclosures in this note apply to all Registrants unless indicated otherwise.

Property, Plant and Equipment is shown functionally on the face of the Registrants' balance sheets. The following tables include the Registrants' total plant balances as of December 31, 2016 and 2015:

December 31, 2016	AEP		APCo	I&M	OPCo	PSO	SWEPCo	
				(in millions)				
Regulated Property, Plant and Equipment								
Generation	$ 19,703.9	(b)	$ 6,332.8	$ 4,056.1	$ —	$ 1,559.3	$ 4,607.6	(b)
Transmission	16,658.6		2,796.9	1,472.8	2,319.2	832.8	1,584.2	
Distribution	18,898.2		3,569.1	1,899.3	4,457.2	2,322.4	2,020.6	
Other	2,902.0		345.1	507.7	433.4	227.3	399.3	
CWIP	3,072.2	(b)	390.3	654.2	221.5	148.2	113.7	(b)
Less: Accumulated Depreciation	16,101.5		3,631.5	2,989.9	2,115.1	1,272.7	2,411.5	
Total Regulated Property, Plant and Equipment - Net	45,133.4		9,802.7	5,600.2	5,316.2	3,817.3	6,313.9	
Nonregulated Property, Plant and Equipment - Net	505.9		23.1	27.3	9.4	5.9	115.6	
Total Property, Plant and Equipment - Net	$ 45,639.3	(a)	$ 9,825.8	$ 5,627.5	$ 5,325.6	$ 3,823.2	$ 6,429.5	

December 31, 2015	AEP		APCo	I&M	OPCo	PSO	SWEPCo	
				(in millions)				
Regulated Property, Plant and Equipment								
Generation	$ 19,082.8	(b)	$ 6,200.8	$ 3,841.7	$ —	$ 1,302.6	$ 3,943.5	(b)
Transmission	14,219.0		2,408.1	1,406.9	2,235.6	815.4	1,387.8	
Distribution	18,046.9		3,402.5	1,790.8	4,287.7	2,206.7	1,957.3	
Other	3,066.7		310.1	511.6	397.8	400.5	582.2	
CWIP	3,774.4	(b)	475.1	519.8	171.9	315.3	744.7	(b)
Less: Accumulated Depreciation	16,076.9		3,395.5	2,908.3	2,047.9	1,352.5	2,445.0	
Total Regulated Property, Plant and Equipment - Net	42,112.9		9,401.1	5,162.5	5,045.1	3,688.0	6,170.5	
Nonregulated Property, Plant and Equipment - Net	4,020.3		23.3	41.0	9.6	5.2	150.6	
Total Property, Plant and Equipment - Net	$ 46,133.2		$ 9,424.4	$ 5,203.5	$ 5,054.7	$ 3,693.2	$ 6,321.1	

(a) Amount excludes $1.8 billion of Property, Plant and Equipment - Net classified as Assets Held for Sale on the balance sheet. See "Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)" section of Note 7 for additional information.

(b) AEP and SWEPCo's regulated generation and regulated CWIP include amounts related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

Depreciation, Depletion and Amortization

The Registrants provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide total regulated annual composite depreciation rates and depreciable lives for the Registrants:

AEP

Functional Class of Property	2016 Annual Composite Depreciation Rate Ranges	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate Ranges	2015 Depreciable Life Ranges (in years)	2014 Annual Composite Depreciation Rate Ranges	2014 Depreciable Life Ranges (in years)
Generation	2.1% - 4.0%	35 - 132	0.4% - 3.1%	35 - 132	1.7% - 3.5%	31 - 132
Transmission	1.5% - 2.7%	15 - 100	1.4% - 2.7%	15 - 81	1.4% - 2.7%	15 - 87
Distribution	2.6% - 3.7%	7 - 156	2.5% - 3.7%	7 - 75	2.4% - 3.7%	7 - 75
Other	3.1% - 8.6%	5 - 84	2.9% - 11.8%	5 - 75	2.1% - 8.6%	5 - 75

APCo

Functional Class of Property	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)	2014 Annual Composite Depreciation Rate	2014 Depreciable Life Ranges (in years)
Generation	3.1%	35 - 121	3.1%	35 - 121	3.1%	40 - 121
Transmission	1.5%	15 - 68	1.6%	15 - 68	1.7%	15 - 87
Distribution	3.7%	10 - 57	3.6%	10 - 57	3.5%	13 - 57
Other	6.0%	5 - 55	8.3%	5 - 55	6.9%	24 - 55

I&M

Functional Class of Property	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)	2014 Annual Composite Depreciation Rate	2014 Depreciable Life Ranges (in years)
Generation	2.4%	59 - 132	2.5%	59 - 132	2.0%	59 - 132
Transmission	1.7%	50 - 75	1.7%	50 - 75	1.7%	50 - 75
Distribution	2.8%	10 - 70	2.8%	10 - 70	2.8%	15 - 70
Other	8.6%	5 - 45	11.8%	5 - 45	6.1%	14 - 45

OPCo

Functional Class of Property	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)	2014 Annual Composite Depreciation Rate	2014 Depreciable Life Ranges (in years)
Transmission	2.3%	39 - 60	2.3%	39 - 60	2.3%	39 - 60
Distribution	2.8%	7 - 57	2.8%	7 - 57	2.7%	7 - 57
Other	5.9%	5 - 50	7.2%	5 - 50	7.0%	7 - 50

PSO

Functional Class of Property	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)	2014 Annual Composite Depreciation Rate	2014 Depreciable Life Ranges (in years)
Generation	2.4%	35 - 85	1.7%	35 - 70	1.7%	35 - 70
Transmission	2.2%	45 - 100	1.9%	40 - 75	1.9%	40 - 75
Distribution	2.7%	27 - 156	2.5%	7 - 65	2.4%	30 - 65
Other	6.4%	5 - 84	4.6%	5 - 40	4.1%	5 - 40

SWEPCo

Functional Class of Property	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate	2015 Depreciable Life Ranges (in years)	2014 Annual Composite Depreciation Rate	2014 Depreciable Life Ranges (in years)
Generation	2.1%	40 - 70	2.2%	40 - 70	2.2%	40 - 70
Transmission	2.2%	50 - 70	2.3%	50 - 70	2.2%	50 - 70
Distribution	2.6%	25 - 65	2.6%	25 - 65	2.7%	25 - 65
Other	6.8%	5 - 51	5.5%	5 - 51	4.8%	7 - 51

The following table includes the nonregulated annual composite depreciation rate ranges and nonregulated depreciable life ranges for AEP. Depreciation rate ranges and depreciable life ranges are not meaningful for nonregulated property of APCo, I&M, OPCo and PSO for 2016, 2015 and 2014.

AEP

Functional Class of Property	2016 Annual Composite Depreciation Rate Ranges	2016 Depreciable Life Ranges (in years)	2015 Annual Composite Depreciation Rate Ranges	2015 Depreciable Life Ranges (in years)	2014 Annual Composite Depreciation Rate Ranges	2014 Depreciable Life Ranges (in years)
Generation	2.8% - 17.2%	40 - 66	2.5% - 3.4%	35 - 66	2.6% - 3.4%	35 - 66
Transmission	2.3%	43 - 55	2.3%	43 - 55	2.3%	43 - 55
Distribution	1.3%	40 50	—%	0 - 0	—%	0 - 0
Other	9.1%	5 - 50 (a)	2.7%	5 - 50 (a)	17.1%	25 - 50 (a)

(a) SWEPCo's nonregulated property, plant and equipment is depreciated using the straight-line method over a range of 3 to 20 years.

SWEPCo provides for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. SWEPCo uses either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. SWEPCo includes these costs in fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities. I&M records ARO for the decommissioning of the Cook Plant. The Registrants have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrants plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrants abandon or cease the use of specific easements, which is not expected.

As of December 31, 2016 and 2015, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.24 billion and $1.18 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2016 and 2015, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $1.95 billion and $1.80 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The Registrants recorded an increase in Asset Retirement Obligations in the second quarter of 2015, primarily related to the final Coal Combustion Residual Rule, which was published in the Federal Register in April 2015. The Federal EPA now regulates 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 Federal EPA regulates CCR as a non-hazardous solid waste and established minimum federal solid waste management standards. Noncash increases related to the CCR Rule are recorded as Property, Plant and Equipment. The following is a reconciliation of the 2016 and 2015 aggregate carrying amounts of ARO by Registrant:

Company	ARO as of December 31, 2015	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31, 2016
				(in millions)		
AEP (c)(d)(e)(f)	$ 1,916.3	$ 91.3	$ 0.8	$ (139.9) (g)	$ 66.4	$ 1,934.9
APCo (c)(f)	140.2	7.6	—	(35.3)	14.6	127.1
I&M (c)(d)(f)	1,253.8	55.6	—	(62.6) (g)	11.3	1,258.1
OPCo (f)	1.4	0.1	0.2	—	—	1.7
PSO (c)(f)	47.8	3.0	0.1	(1.0)	3.5	53.4
SWEPCo (c)(e)(f)	125.4	7.0	0.2	(8.3)	32.2	156.5

Company	ARO as of December 31, 2014	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31, 2015
				(in millions)		
AEP (c)(d)(e)(f)	$ 2,019.6	$ 101.4	$ 58.0	$ (147.2) (a)	$ (115.5) (b)	$ 1,916.3
APCo (c)(f)	148.4	8.3	—	(34.0)	17.5	140.2
I&M (c)(d)(f)	1,342.5	64.3	—	(5.7)	(147.3)	1,253.8
OPCo (f)	1.4	—	—	—	—	1.4
PSO (c)(f)	38.1	2.6	5.6	(0.4)	1.9	47.8
SWEPCo (c)(e)(f)	94.4	5.9	17.1	(5.0)	13.0	125.4

(a) Amount includes settlement of liabilities of $81 million associated with the sale of the Muskingum River Plant site. See the “Muskingum River Plant” section of Note 7.
(b) Amount includes a $20 million reduction in the ARO liability due to the execution of a joint use agreement with a third party.
(c) Includes ARO related to ash disposal facilities.
(d) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.24 billion and $1.18 billion as of December 31, 2016 and 2015, respectively.
(e) Includes ARO related to Sabine and DHLC.
(f) Includes ARO related to asbestos removal.
(g) Amount includes settlement of liabilities of $61 million associated with the sale of the Tanners Creek Plant site. See the “Tanners Creek” section of Note 7.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

The Registrants’ amounts of Allowance for Equity Funds Used During Construction are summarized in the following table:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
AEP	$ 113.2	$ 131.9	$ 102.9
APCo	11.7	13.8	7.1
I&M	15.3	11.6	18.9
OPCo	6.0	8.8	6.9
PSO	6.2	8.8	3.1
SWEPCo	11.0	26.4	11.9

The Registrants' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

Company	Years Ended December 31, 2016	2015	2014
		(in millions)	
AEP	$ 51.7	$ 61.3	$ 44.5
APCo	6.3	6.9	3.8
I&M	7.2	5.0	8.0
OPCo	3.3	4.8	4.4
PSO	3.4	5.0	1.8
SWEPCo	6.9	14.8	6.9

Jointly-owned Electric Facilities (Applies to AEP, I&M, PSO and SWEPCo)

The Registrants have electric facilities that are jointly-owned with affiliated and non-affiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. Each Registrant's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

	Fuel Type	Percent of Ownership	Registrant's Share as of December 31, 2016: Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Conesville Generating Station, Unit 4 (a) (k)	Coal	43.5%	$ 0.1	$ 1.3	$ —
J.M. Stuart Generating Station (b)	Coal	26.0%	—	0.8	—
Wm. H. Zimmer Generating Station (c) (k)	Coal	25.4%	—	0.3	—
Dolet Hills Generating Station, Unit 1 (i)	Lignite	40.2%	334.8	5.0	207.5
Flint Creek Generating Station, Unit 1 (j)	Coal	50.0%	362.4	3.7	73.5
Pirkey Generating Station, Unit 1 (j)	Lignite	85.9%	586.4	5.7	399.5
Oklaunion Generating Station, Unit 1 (h)	Coal	70.3%	454.8	1.3	246.0
Turk Generating Plant (j)	Coal	73.3%	1,657.3	0.2	138.5
Transmission	NA	(d)	62.4	0.5	45.1
Total			$ 3,458.2	$ 18.8	$ 1,110.1
I&M					
Rockport Generating Plant (e)(f)(g)	Coal	50.0%	$ 936.1	$ 125.8	$ 535.1
PSO					
Oklaunion Generating Station, Unit 1 (h)	Coal	15.6%	$ 105.2	$ 0.5	$ 59.4
SWEPCo					
Dolet Hills Generating Station, Unit 1 (i)	Lignite	40.2%	$ 334.8	$ 5.0	$ 207.5
Flint Creek Generating Station, Unit 1 (j)	Coal	50.0%	362.4	3.7	73.5
Pirkey Generating Station, Unit 1 (j)	Lignite	85.9%	586.4	5.7	399.5
Turk Generating Plant (j)	Coal	73.3%	1,657.3	0.2	138.5
Total			$ 2,940.9	$ 14.6	$ 819.0

	Fuel Type	Percent of Ownership	Registrant's Share as of December 31, 2015 Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Conesville Generating Station, Unit 4 (a) (k)	Coal	43.5%	$ 337.4	$ 2.4	$ 76.1
J.M. Stuart Generating Station (b)	Coal	26.0%	565.5	12.9	221.8
Wm. H. Zimmer Generating Station (c) (k)	Coal	25.4%	815.5	6.4	421.7
Dolet Hills Generating Station, Unit 1 (i)	Lignite	40.2%	332.4	3.9	205.9
Flint Creek Generating Station, Unit 1 (j)	Coal	50.0%	131.4	195.0	70.0
Pirkey Generating Station, Unit 1 (j)	Lignite	85.9%	572.1	5.9	389.1
Oklaunion Generating Station, Unit 1 (h)	Coal	70.3%	445.5	7.2	236.2
Turk Generating Plant (j)	Coal	73.33%	1,649.0	5.5	104.1
Transmission	NA	(d)	68.5	0.4	48.1
Total			$ 4,917.3	$ 239.6	$ 1,773.0
I&M					
Rockport Generating Plant (e)(f)(g)	Coal	50.0%	$ 926.7	$ 58.5	$ 512.4
PSO					
Oklaunion Generating Station, Unit 1 (h)	Coal	15.6%	$ 103.0	$ 1.8	$ 58.2
SWEPCo					
Dolet Hills Generating Station, Unit 1 (i)	Lignite	40.2%	$ 332.4	$ 3.9	$ 205.9
Flint Creek Generating Station, Unit 1 (j)	Coal	50.0%	131.4	195.0	70.0
Pirkey Generating Station, Unit 1 (j)	Lignite	85.9%	572.1	5.9	389.1
Turk Generating Plant (j)	Coal	73.33%	1,649.0	5.5	104.1
Total			$ 2,684.9	$ 210.3	$ 769.1

(a) Operated by AGR. See the "Impairments" section of Note 7.
(b) Operated by Dayton Power & Light Company, a non-affiliated company. See the "Impairments" section of Note 7.
(c) Operated by Dynegy Corporation, a non-affiliated company. See the "Impairments" section of Note 7.
(d) Varying percentages of ownership.
(e) Operated by I&M.
(f) Amounts include I&M's 50% ownership of both Unit 1 and capital additions for Unit 2. Unit 2 is subject to an operating lease with a non-affiliated company. See the "Rockport Lease" section of Note 13.
(g) AEGCo owns 50% of Unit 1 with I&M and 50% of capital additions for Unit 2.
(h) Operated by PSO, which owns 15.6%. Also jointly-owned (54.7%) by AEP Texas and various non-affiliated companies. See the "Impairments" section of Note 7.
(i) Operated by CLECO, a non-affiliated company.
(j) Operated by SWEPCo.
(k) In February 2017, AEP signed an agreement to purchase Dynegy Corporation's ownership share of Conesville Generating Station, Unit 4. Simultaneously, AEP signed an agreement with Dynegy Corporation to sell AEP's ownership share of the Wm. H. Zimmer Generating Station. The transactions are expected to close in the second quarter of 2017, subject to FERC approval and are not expected to have a material impact on net income, cash flows and financial condition.
NA Not applicable.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The disclosures in this note apply to all Registrants unless indicated otherwise.

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. The unaudited quarterly financial information for each Registrant is as follows:

Quarterly Periods Ended:	AEP		APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
March 31, 2016							
Total Revenues	$ 4,044.9		$ 820.0	$ 532.7	$ 763.6	$ 274.3	$ 379.0
Operating Income	892.9		244.4	115.8	134.0	35.8	51.4
Income from Continuing Operations	503.1		—	—	—	—	—
Net Income	503.1		126.3	74.7	70.2	15.7	24.5
June 30, 2016							
Total Revenues	$ 3,892.9		$ 673.5	$ 522.4	$ 730.8	$ 300.2	$ 427.0
Operating Income	866.2		158.3	94.8	138.6	59.0	85.9
Income from Continuing Operations	506.4		—	—	—	—	—
Income (Loss) from Discontinued Operations, Net of Tax	(2.5)	(a)	—	—	—	—	—
Net Income	503.9		73.4	51.3	74.6	28.9	44.3
September 30, 2016							
Total Revenues	$ 4,652.2		$ 778.2	$ 597.6	$ 871.3	$ 401.7	$ 539.7
Operating Income (Loss)	(1,127.9)	(b)	204.4	131.4	171.6	98.4	147.4
Income (Loss) from Continuing Operations	(764.2)	(b)	—	—	—	—	—
Net Income (Loss)	(764.2)	(b)	104.1	75.4	99.9	52.8	84.4
December 31, 2016							
Total Revenues	$ 3,790.1		$ 729.5	$ 514.9	$ 588.2	$ 273.6	$ 402.3
Operating Income	575.9		136.2	39.6	64.3	5.5	36.4
Income from Continuing Operations	375.2		—	—	—	—	—
Net Income	375.2		65.3	38.5	37.5	2.6	16.5

Quarterly Periods Ended:	AEP		APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
March 31, 2015							
Total Revenues	$ 4,580.4		$ 899.0	$ 586.3	$ 918.4	$ 306.8	$ 431.7
Operating Income	1,102.8		273.5	124.4	122.9	34.9	92.3
Income from Continuing Operations	620.2		—	—	—	—	—
Income from Discontinued Operations, Net of Tax	10.5		—	—	—	—	—
Net Income	630.7		141.8	72.7	65.4	13.7	46.7
June 30, 2015							
Total Revenues	$ 3,826.7		$ 682.0	$ 544.3	$ 705.8	$ 319.5	$ 438.1
Operating Income	804.1		145.7	91.4	96.5	55.5	110.1
Income from Continuing Operations	431.4		—	—	—	—	—
Income (Loss) from Discontinued Operations, Net of Tax	(0.1)		—	—	—	—	—
Net Income	431.3		59.0	50.6	47.7	27.1	59.5
September 30, 2015							
Total Revenues	$ 4,431.4		$ 727.5	$ 568.3	$ 782.3	$ 420.3	$ 532.5
Operating Income	960.2		157.9	103.4	140.9	84.5	141.2
Income from Continuing Operations	511.8		—	—	—	—	—
Income from Discontinued Operations, Net of Tax	7.8		—	—	—	—	—
Net Income	519.6		74.6	56.6	71.6	44.7	82.1
December 31, 2015							
Total Revenues	$ 3,614.7		$ 655.0	$ 487.3	$ 692.2	$ 292.6	$ 378.6
Operating Income	466.4		133.7	50.7	100.5	18.3	25.6
Income from Continuing Operations	205.2		—	—	—	—	—
Income from Discontinued Operations, Net of Tax	265.5	(c)	—	—	—	—	—
Net Income	470.7		65.2	24.9	48.0	7.0	7.7

(a) Includes final accounting adjustment for sale of AEPRO (see Note 7).
(b) Includes impairments for Merchant Generating Assets (see Note 7).
(c) Includes sale of AEPRO (see Note 7).

AEP

The unaudited quarterly financial information relating to Common Shareholders is as follows:

	2016 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Earnings (Loss) Attributable to AEP Common Shareholders	$ 501.2	$ 502.1	$ (765.8) (a)	$ 373.4
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders from Continuing Operations (b)	1.02	1.03	(1.56) (a)	0.76
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders from Discontinued Operations (c)	—	(0.01)	—	—
Total Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders (b)	1.02	1.02	(1.56) (a)	0.76
Diluted Earnings (Loss) per Share Attributable to AEP Common Shareholders from Continuing Operations (b)	1.02	1.03	(1.56) (a)	0.76
Diluted Earnings (Loss) per Share Attributable to AEP Common Shareholders from Discontinued Operations (c)	—	(0.01)	—	—
Total Diluted Earnings (Loss) per Share Attributable to AEP Common Shareholders (b)	1.02	1.02	(1.56) (a)	0.76

	2015 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Earnings Attributable to AEP Common Shareholders	$ 629.2	$ 430.0	$ 518.3	$ 469.6
Basic Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (b)	1.27	0.88	1.04	0.41
Basic Earnings per Share Attributable to AEP Common Shareholders from Discontinued Operations (d)	0.02	—	0.02	0.54
Total Basic Earnings per Share Attributable to AEP Common Shareholders (b)	1.29	0.88	1.06	0.95
Diluted Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (b)	1.27	0.88	1.04	0.41
Diluted Earnings per Share Attributable to AEP Common Shareholders from Discontinued Operations (d)	0.02	—	0.02	0.54
Total Diluted Earnings per Share Attributable to AEP Common Shareholders (b)	1.29	0.88	1.06	0.95

(a) Relates to impairments for Merchant Generating Assets (see Note 7).
(b) Quarterly Earnings per Share amounts are intended to be stand-alone calculations and are not always additive to full-year amount due to rounding.
(c) Relates to final accounting adjustment for sale of AEPRO (see Note 7).
(d) Relates to sale of AEPRO (see Note 7).

20. GOODWILL AND OTHER INTANGIBLE ASSETS

The disclosures in this note apply to AEP only.

Goodwill

The changes in AEP's carrying amount of goodwill for the years ended December 31, 2016 and 2015 by operating segment are as follows:

	Corporate and Other	Generation and Marketing	AEP Consolidated
		(in millions)	
Balance as of December 31, 2014	$ 75.9	$ 15.4	$ 91.3
Impairment Losses	—	—	—
Goodwill Written Off Related to Sale of AEPRO	(38.8)	—	(38.8)
Balance as of December 31, 2015	37.1	15.4	52.5
Impairment Losses	—	—	—
Balance as of December 31, 2016	$ 37.1	$ 15.4	$ 52.5

In the fourth quarters of 2016 and 2015, annual impairment tests were performed. The fair values of the reporting units with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. AEP does not have any accumulated impairment on existing goodwill.

Other Intangible Assets

Acquired intangible assets subject to amortization were $2 million as of December 31, 2015, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on the balance sheet. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2016		2015	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)		(in millions)		
Acquired Customer Contracts	5	$ 58.3	$ 58.3	$ 58.3	$ 56.5

Amortization of intangible assets was $2 million, $3 million and $5 million for the years ended December 31, 2016, 2015 and 2014, respectively. Intangible assets were fully amortized as of December 31, 2016.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing - The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page - Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings - Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders - (Stock held in a bank or brokerage account) - When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan - A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/buyandmanagestock.

Financial Community Inquiries - Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; Individual shareholders should contact Kathleen Kozero, 614-716-2819, klkozero@AEP.com.

Number of Shareholders - As of February 28, 2017, there were approximately 66,000 registered shareholders and approximately 638,000 shareholders holding stock in street name through a bank or broker. There were 491,712,071 shares outstanding as of February 28, 2017.

Form 10-K - Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2016. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at klkozero@AEP.com.

Executive Leadership Team

Name	Age	Office
Nicholas K. Akins	56	Chairman of the Board, President and Chief Executive Officer
Lisa M. Barton	51	Executive Vice President - Transmission
Paul Chodak, III	53	Executive Vice President - Utilities
David M. Feinberg	47	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	56	Executive Vice President and Chief Administrative Officer
Mark C. McCullough	57	Executive Vice President - Generation
Charles R. Patton	57	Executive Vice President - External Affairs
Robert P. Powers	63	Vice Chairman
Brian X. Tierney	49	Executive Vice President and Chief Financial Officer
Charles E. Zebula	56	Executive Vice President - Energy Supply

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