UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **September 30, 2019**
or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

Commission File Number	Registrants; Address and Telephone Number	States of Incorporation	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER CO INC.	New York	13-4922640
333-221643	AEP TEXAS INC.	Delaware	51-0007707
333-217143	AEP TRANSMISSION COMPANY, LLC	Delaware	46-1125168
1-3457	APPALACHIAN POWER COMPANY	Virginia	54-0124790
1-3570	INDIANA MICHIGAN POWER COMPANY	Indiana	35-0410455
1-6543	OHIO POWER COMPANY	Ohio	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA	Oklahoma	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY	Delaware	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215-2373		
	Telephone (614) 716-1000		

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Trading Symbol	Name of Each Exchange on Which Registered
American Electric Power Company Inc.	Common Stock, $6.50 par value	AEP	New York Stock Exchange
American Electric Power Company Inc.	6.125% Corporate Units	AEP PR B	New York Stock Exchange

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit such files).

Yes ☒ No ☐

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Smaller reporting company ☐ Emerging growth company ☐

Indicate by check mark whether AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers, smaller reporting companies, or emerging growth companies. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

Smaller reporting company ☐ Emerging growth company ☐

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

☐

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

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

	Number of shares of common stock outstanding of the Registrants as of October 24, 2019
American Electric Power Company, Inc.	493,951,812
	($6.50 par value)
AEP Texas Inc.	100
	($0.01 par value)
AEP Transmission Company, LLC (a)	NA
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	7,536,640
	($18 par value)

(a) 100% interest is held by AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of American Electric Power Company, Inc.

NA Not applicable.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
September 30, 2019

This combined Form 10-Q is separately filed by American Electric Power Company, Inc., AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants.

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
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.
AEP Wind Holdings LLC	Acquired in April 2019 as Sempra Renewables LLC, develops, owns and operates, or holds interests in, wind generation facilities in the United States.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AFUDC	Allowance for Equity Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
ALJ	Administrative Law Judge.
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 VIE formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
APSC	Arkansas Public Service Commission.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for rate-making purposes.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
Cardinal Operating Company	A jointly-owned organization between AGR and a nonaffiliate. The nonaffiliate operates the three unit Cardinal Plant and wholly-owns Units 2 and 3.
CO_2	Carbon dioxide and other greenhouse gases.
Conesville Plant	A generation plant consisting of three coal-fired generating units totaling 1,695 MW located in Conesville, Ohio. The plant is jointly-owned by AGR and a nonaffiliate.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,278 MW nuclear plant owned by I&M.
CSAPR	Cross-State Air Pollution Rule.
CWA	Clean Water Act.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel VIII, DCC Fuel IX, DCC Fuel X, DCC Fuel XI, DCC Fuel XII and DCC Fuel XIII, consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.

Term	Meaning
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
DIR	Distribution Investment Rider.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE 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.
Equity Units	AEP's Equity Units issued in March 2019.
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 AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
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.
Global Settlement	In February 2017, the PUCO approved a settlement agreement filed by OPCo in December 2016 which resolved all remaining open issues on remand from the Supreme Court of Ohio in OPCo's 2009 - 2011 and June 2012 - May 2015 ESP filings. It also resolved all open issues in OPCo's 2009, 2014 and 2015 SEET filings and 2009, 2012 and 2013 Fuel Adjustment Clause Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
MISO	Midcontinent Independent System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NAAQS	National Ambient Air Quality Standards.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
North Central Wind Energy Facilities	A proposed joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,485 MWs of wind generation.
NO_2	Nitrogen dioxide.
NO_x	Nitrogen oxide.
NPDES	National Pollutant Discharge Elimination System.
NSR	New Source Review.

Term	Meaning
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 VIE formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
Oklaunion Power Station	A single unit coal-fired generation plant totaling 650 MW located in Vernon, Texas. The plant is jointly-owned by AEP Texas, PSO and certain nonaffiliated entities.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
OSS	Off-system Sales.
OTC	Over-the-counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTC	Production Tax Credits.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Racine	A generation plant consisting of two hydroelectric generating units totaling 47.5 MWs located in Racine, Ohio and owned by AGR.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Restoration Funding	AEP Texas Restoration Funding LLC, a wholly-owned subsidiary of AEP Texas and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Texas primarily caused by Hurricane Harvey.
Risk Management Contracts	Trading and non-trading 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.
ROE	Return on Equity.
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 VIE for AEP and SWEPCo.
Santa Rita East	Santa Rita East Wind Holdings, LLC, a consolidated VIE whose sole purpose is to own and operate a 302.4 MW wind generation facility in west Texas in which AEP owns a 75% interest.
SCR	Selective Catalytic Reduction, NO_x reduction technology at Rockport Plant.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019, consists of 724 MWs of wind generation and battery assets in the United States.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.

Term	Meaning
SSO	Standard service offer.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCC	Formerly AEP Texas Central Company, now a division of AEP Texas.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
Transition Funding	AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated VIEs formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated VIE formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UPA	Unit Power Agreement.
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.
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project that was cancelled in July 2018. The project included the acquisition of a wind generation facility, totaling approximately 2,000 MW of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2018 Annual Report, but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements 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:

- Changes in economic conditions, electric 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.
- Decreased demand for electricity.
- 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 SNF.
- The availability of fuel and 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 or acquire renewable generation, 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 PM 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 coal ash and nuclear fuel.
- 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.
- 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 coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within RTOs including ERCOT, PJM and SPP.
- 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, OPEB, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
- Accounting standards periodically issued by accounting standard-setting bodies.

- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber security threats and other catastrophic events.
- The ability to attract and retain the requisite work force and key personnel.

The forward-looking statements of the Registrants speak only as of the date of this report or as of the date they are made. The Registrants expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see “Risk Factors” in Part I of the 2018 Annual Report and in Part II of this report.

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

EXECUTIVE OVERVIEW

Customer Demand

AEP's weather-normalized retail sales volumes for the third quarter of 2019 were flat compared to the third quarter of 2018. AEP's third quarter 2019 industrial sales decreased by 1.1% compared to the third quarter of 2018. The decline in industrial sales was spread across most operating companies and most industries outside of the oil and gas sector. Weather-normalized residential sales increased 0.7% while weather-normalized commercial sales increased by 0.4% in the third quarter of 2019 compared to the third quarter of 2018.

AEP's weather-normalized retail sales volumes for the nine months ended September 30, 2019 decreased by 0.6% compared to the nine months ended September 30, 2018. AEP's industrial sales volumes for the nine months ended September 30, 2019 decreased 1.4% compared to the nine months ended September 30, 2018. The decline in industrial sales was spread across most operating companies and most industries outside of the oil and gas sector. Weather-normalized commercial sales decreased 0.7% for the nine months ended September 30, 2019 compared to the nine months ended September 30, 2018, while weather-normalized residential sales increased by 0.2%.

Regulatory Matters

AEP's public utility subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Depending on the outcomes, these rate and regulatory proceedings can have a material impact on results of operations, cash flows and possibly financial condition. AEP is currently involved in the following key proceedings. See Note 4 - Rate Matters for additional information.

- In May 2019, AEP Texas filed a request with the PUCT for a $56 million annual increase in rates based upon a proposed 10.5% return on common equity. In July and August 2019, PUCT Staff and various intervenors filed testimony that includes recommended disallowances that could potentially result in write-offs exceeding $450 million. The PUCT staff's recommended disallowances primarily consisted of $85 million in capital incentives and $26 million for capitalized vegetation management expenses. The intervenors recommended disallowances primarily consisted of (a) $173 million for a newly constructed transmission operations center and other service centers, (b) $94 million for Hurricane Harvey costs, (c) $36 million for capitalized cross arms and (d) $21 million for capitalized plant costs related to unreimbursed damages to assets caused by third-parties. In addition, one intervenor recommended AEP Texas refund $115 million of Excess ADIT, which includes $2 million in interest, related to previously owned deregulated generation assets. AEP Texas recorded $113 million as a favorable adjustment to income tax expense in 2017 as a result of Tax Reform. The PUCT is expected to issue an order on the case by the first quarter of 2020.

- In May 2019, I&M filed a request with the IURC for a $172 million annual increase. The requested increase in Indiana rates would be phased in through January 2021 and is based upon a proposed 10.5% return on common equity. In August 2019, various intervenors filed testimony that includes recommended disallowances that could potentially result in write-offs of $41 million related to the remaining book value of existing Indiana jurisdictional meters and $11 million associated with certain Cook Plant study costs. The IURC is expected to issue an order on the case by the first quarter of 2020.

- *Virginia Legislation Affecting Earnings Reviews* - In March 2018, Virginia enacted legislation requiring APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 test years (triennial review). Triennial reviews are subject to an earnings test which provides that 70% of any earnings exceeding 70 basis points over the Virginia SCC authorized return on common equity would be refunded to customers or be used to lower APCo's Virginia retail base rates on a prospective basis. The Virginia legislation also states that, under certain circumstances, costs associated with asset impairments related to early retirement determinations made by a utility for generation facilities fueled by coal, natural gas or oil or for automated meters be considered fully recovered in the period recorded. Management has reviewed APCo's actual and forecasted earnings for the triennial period and concluded that it is not probable, but is reasonably possible, that APCo will over-earn in Virginia during the 2017-2019 triennial period. Due to various uncertainties, including weather, storm restoration, weather-normalized demand and potential customer shopping during 2019, management cannot estimate a range of potential APCo Virginia over-earnings during the 2017-2019 triennial period.

- *Virginia Staff Depreciation Study Request* - In November 2018, Virginia staff recommended that APCo implement new Virginia jurisdictional depreciation rates effective January 1, 2018 based on APCo's depreciation study that was prepared at Virginia staff's request using December 31, 2017 APCo property balances. Implementation of those depreciation rates would result in a $21 million pretax increase in annual depreciation expense with no corresponding increase in retail base rates. In December 2018, APCo submitted a response to the Virginia Staff stating that it was inappropriate for APCo to change Virginia depreciation rates in advance of APCo's triennial review, citing the Virginia SCC's November 2014 order to not change APCo's Virginia depreciation rates until APCo's next base rate case/review.

- *2020 Increase in West Virginia Retail Rates for WPCo 17.5% Merchant Share of Mitchell Plant* - In January 2015, the WVPSC approved a settlement agreement in which 82.5% of the costs associated with WPCo's acquired interest were prospectively reflected in retail rates with the remaining 17.5% of costs associated with the acquired interest to be included in rates starting January 2020. APCo and WPCo file joint retail rates in West Virginia. In June 2019, APCo and WPCo filed with the WVPSC to increase each company's retail rates (through a surcharge) starting January 1, 2020 to reflect the recovery of WPCo's remaining 17.5% interest in the Mitchell Plant. The joint filing will increase APCo's and WPCo's combined West Virginia retail rates by approximately $21 million annually.

- *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. In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In August 2018, SWEPCo filed a Motion for Reconsideration at the Court of Appeals, which was denied. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. In May 2019, various intervenors filed replies to the petition. In July 2019, SWEPCo filed its response to these briefs. The Texas Supreme Court has requested full briefing by the parties. SWEPCo's initial brief is due in October 2019. Response briefs are due in November 2019 and SWEPCo's reply brief is due in December 2019. As of September 30, 2019, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. SWEPCo's Texas jurisdictional share of the Turk Plant investment is approximately 33%.

- In July 2019, clean energy legislation which offers incentives for power-generating facilities with zero or reduced carbon emissions was signed into law by the Ohio Governor. The clean energy legislation phases out current energy efficiency and renewable mandates no later than 2020 and after 2026, respectively. The bill provides for the recovery of existing renewable energy contracts on a bypassable basis through 2032. The clean energy legislation also includes a provision for recovery of OVEC costs through 2030 which will be allocated to all electric distribution utilities on a non-bypassable basis. OPCo's Inter-Company Power Agreement for OVEC terminates in June 2040. To the extent that OPCo is unable to recover the costs of renewable energy contracts on a bypassable basis by the end of 2032, recover costs of OVEC after 2030 or fully recover energy efficiency costs through 2020 it could reduce future net income and cash flows and impact financial condition.

Utility Rates and Rate Proceedings

The Registrants file rate cases with their regulatory commissions in order to establish fair and appropriate electric service rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Registrants' current and future results of operations, cash flows and financial position.

The following tables show the Registrants' completed and pending base rate case proceedings in 2019. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase	Approved ROE	New Rates Effective
		(in millions)		
APCo	West Virginia	$ 35.8	9.75%	March 2019
WPCo	West Virginia	8.4	9.75%	March 2019
PSO	Oklahoma	46.0	9.4%	April 2019

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase	Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE
			(in millions)		
SWEPCo (a)	Arkansas	February 2019	$ 67.0	10.5%	9% - 9.5%
AEP Texas	Texas	May 2019	56.0	10.5%	9% - 9.35%
I&M	Indiana	May 2019	172.0	10.5%	9% - 9.73%
I&M	Michigan	June 2019	58.4	10.5%	9.1% - 9.75%

(a) In October 2019, SWEPCo, the APSC staff and various intervenors filed a stipulation and settlement agreement with the APSC that included a base rate increase of $24 million based upon a 9.45% return on common equity. See "2019 Arkansas Base Rate Case" section of Note 4 for additional information.

Renewable Generation

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

Contracted Renewable Generation Facilities

AEP continues to develop its renewable portfolio within the Generation & Marketing segment. Activities include working 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. The Generation & Marketing segment also develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with creditworthy counterparties.

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation and battery assets valued at approximately $1.1 billion. AEP paid $583 million in cash and acquired a 50% ownership interest in five non-consolidated joint ventures with net assets valued at $406 million as of the acquisition date (which includes $364 million of existing debt obligations). Additionally, the transaction included the acquisition of two tax equity partnerships and the associated recognition of noncontrolling tax equity interest of $135 million. The wind generation portfolio includes seven wind farms with long-term PPAs for 100% of their energy production. Five of the wind farms are jointly-owned with BP Wind Energy and two wind farms are consolidated by AEP and are tax equity partnerships with nonaffiliated noncontrolling interests. See "Acquisitions" section of Note 6 for additional information.

In July 2019, AEP acquired a 75% interest, or 227 MWs, in Santa Rita East for approximately $356 million. The project is located in west Texas and was placed in-service in July 2019. Long-term virtual power purchase agreements are in place with nonaffiliates for the project's generation. See "Acquisitions" section of Note 6 for additional information.

As of September 30, 2019, subsidiaries within AEP's Generation & Marketing segment had approximately 1,396 MWs of contracted renewable generation projects in-service. In addition, as of September 30, 2019, these subsidiaries had approximately 54 MWs of renewable generation projects under construction with total estimated capital costs of $67 million related to these projects.

Regulated Renewable Generation Facilities

In September 2018, OPCo, consistent with its commitment in the previously approved PPA application, submitted a filing with the PUCO demonstrating a need for up to 900 MWs of economically beneficial renewable resources in Ohio. This filing was followed by a separate filing for two solar Renewable Energy Purchase Agreements totaling 400 MWs. In January 2019, PUCO staff recommended that the PUCO reject OPCo's request. If approved, the solar generation facilities are expected to be operational by the end of 2021.

In July 2019, PSO and SWEPCo submitted filings before their respective commissions for the approval to acquire the North Central Wind Energy Facilities, comprised of three Oklahoma wind facilities totaling 1,485 MWs, on a fixed cost turn-key basis at completion. Subject to regulatory approval, PSO will own 45.5% and SWEPCo will own 55.5% of the project, which will cost approximately $2 billion. Two wind facilities, totaling 1,286 MWs, would qualify for 80% of the federal PTC with year-end 2021 in-service dates. The third wind facility (199 MWs) would qualify for 100% of the PTC with a year-end 2020 in-service date. The acquisition can be scaled, subject to commercial limitation, to align with individual state resource needs and approvals. Hearings are scheduled for the first quarter of 2020. PSO and SWEPCo are seeking regulatory approvals by July 2020.

Racine

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017. Due to a significant increase in estimated costs to complete the reconstruction project, AEP recorded impairments in 2017 and 2018. See Note 7 - Dispositions and Impairments in the 2018 Annual Report for additional information.

Due to weather-related delays in the first quarter of 2019, reconstruction activities at Racine are now estimated to be completed in the first half of 2020. AEP expects to incur additional capital expenditures to complete the reconstruction project, at which point the fair value of Racine, as fully operational, is expected to approximate the book value once complete. Future revisions in cost estimates or delays in completion could result in additional losses which could reduce future net income and cash flows and impact financial condition.

Dolet Hills Lignite Company Operations

During the second quarter of 2019, Dolet Hills Power Station switched to a seasonal operational strategy. DHLC's mining operation will continue year-round but will reduce its lignite output. SWEPCo's share of the net investment in the Dolet Hills Power Station is $129 million and the maximum exposure of SWEPCo's total investment in DHLC is $153 million. Management will continue to monitor the economic viability of the Dolet Hills Power Station and DHLC.

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. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition. See Note 4 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies for additional information.

Rockport Plant Litigation

In 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would 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, refueling or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

AEGCo and I&M sought and were granted dismissal by the U.S. District Court for the Southern District of Ohio of certain of the plaintiffs' claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. Plaintiffs voluntarily dismissed the surviving claims that AEGCo and I&M failed to exercise prudent utility practices with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit.

In 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion and judgment affirming the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims, reversing the district court's dismissal of the breach of contract claims and remanding the case for further proceedings.

Thereafter, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree. The district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. The consent decree was modified based on an agreement among the parties in July 2019. The district court entered a stipulated order to stay the lease litigation to afford time for the parties in the lease litigation to engage in settlement discussions. See "Modification of the NSR Litigation Consent Decree" section below for additional information.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management cannot determine a range of potential losses that are reasonably possible of occurring.

Patent Infringement Complaint

In July 2019, Midwest Energy Emissions Corporation and MES Inc. (collectively, the plaintiffs) filed a patent infringement complaint against various parties, including AEP Texas, AGR, Cardinal Operating Company and SWEPCo (collectively, the AEP Defendants). The complaint alleges that the AEP Defendants infringed two patents owned by the plaintiffs by using specific processes for mercury control at certain coal-fired generating stations. The complaint seeks injunctive relief and damages. Management will continue to defend against the claims. Management is unable to determine a range of potential loss that is reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP has a substantial capital investment program and incurs additional operational costs to comply with environmental control requirements. Additional investments and operational changes will be made in response to existing and anticipated requirements to reduce emissions from fossil generation, rules governing the beneficial use and disposal of coal combustion by-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 other parties challenged some of the Federal EPA requirements. Management is engaged in the development of possible future requirements including the items discussed below. Management believes that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

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 cannot 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 below will have a material impact on AEP System generating units. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of September 30, 2019, the AEP System had generating capacity of approximately 25,500 MWs, of which approximately 13,200 MWs were coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on fossil generation. Based upon management estimates, AEP's investment to meet these existing and proposed requirements ranges from approximately $550 million to $1.1 billion through 2026.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in finalizing proposed rules or revising certain existing requirements. The cost estimates will also change based on: (a) potential state rules that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) actual performance of the pollution control technologies installed, (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 continues to evaluate the economic feasibility of environmental investments on regulated and competitive plants.

The table below represents the net book value before cost of removal, including related materials and supplies inventory, of plants or units of plants previously retired that have a remaining net book value as of September 30, 2019.

Company	Plant Name and Unit	Generating Capacity (in MWs)	Amounts Pending Regulatory Approval (in millions)
APCo	Kanawha River Plant	400	$ 43.8
APCo	Clinch River Plant, Unit 3	235	31.8
APCo (a)	Clinch River Plant, Units 1 and 2	470	29.2
APCo	Sporn Plant, Units 1 and 3	300	15.6
APCo	Glen Lyn Plant	335	13.5
SWEPCo (b)	Welsh Plant, Unit 2	528	50.6
Total		2,268	$ 184.5

(a) APCo obtained permits following the Virginia SCC's and WVPSC's approval to convert Clinch River Plant, Units 1 and 2 to natural gas. In 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Clinch River Plant, Units 1 and 2 began operations as natural gas units in 2016.

(b) In October 2019, SWEPCo filed a stipulation and settlement agreement with the APSC, which includes recovery of the remaining $15 million Arkansas jurisdictional share of the net book value of Welsh Plant, Unit 2. An order from the APSC is expected in the fourth quarter of 2019.

Management is seeking or will seek recovery of the remaining net book value in future rate proceedings. To the extent the net book value of these generation assets is not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Modification of the New Source Review Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle claims that the AEP subsidiaries violated the NSR provisions of the CAA when they undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_x emissions from the AEP System and various mitigation projects.

In 2017, AEP filed a motion with the district court seeking to modify the consent decree to eliminate an obligation to install future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. The other parties to the consent decree opposed AEP's motion. The district court granted AEP's request to delay the deadline to install SCR technology at Rockport Plant, Unit 2 until June 2020.

In May 2019, the parties filed a proposed order to modify the consent decree. The proposed order requires AEP to enhance the dry sorbent injection system on both units at the Rockport Plant by the end of 2020, and meet 30-day rolling average emission rates for SO_2 and NO_x at the combined stack for the Rockport Plant beginning in 2021. Total SO_2 emissions from the Rockport Plant are limited to 10,000 tons per year beginning in 2021 and reduce to 5,000 tons per year when Rockport Plant, Unit 1 retires in 2028. The proposed modification was approved by the district court and became effective in July 2019. As part of the modification to the consent decree, I&M agreed to provide an additional $7.5 million to citizens' groups and the states for environmental mitigation projects. As joint owners in the Rockport Plant, the $7.5 million payment was shared between AEGCo and I&M based on the joint ownership agreement.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP's existing generating units include: (a) periodic revisions to NAAQS and the development of SIPs to achieve any more stringent standards, (b) implementation of the regional haze program by the states and the Federal EPA, (c) regulation of hazardous air pollutant emissions under MATS, (d) implementation and review of CSAPR and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil generation under Section 111 of the CAA. Notable developments in significant CAA regulatory requirements affecting AEP's operations are discussed in the following sections.

National Ambient Air Quality Standards

The Federal EPA issued new, more stringent NAAQS for PM in 2012 and ozone in 2015. The existing standards for NO_2 and SO_2 were retained after review by the Federal EPA in 2018 and 2019, respectively. Implementation of these standards is underway.

In 2016, the Federal EPA completed an integrated review plan for the 2012 PM standard. Work is currently underway on scientific, risk and policy assessments necessary to develop a proposed rule, which is anticipated in 2021.

The Federal EPA finalized non-attainment designations for the 2015 ozone standard in 2018. The Federal EPA has confirmed that for states included in the CSAPR program, there are no additional interstate transport obligations, as all areas of the country are expected to attain the 2008 ozone standard before 2023. Challenges to the 2015 ozone standard and the Federal EPA's determination that CSAPR satisfies certain states' interstate transport obligations are pending in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal EPA proposed final requirements for implementing the 2015 ozone standard, which have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. Management cannot currently predict the nature, stringency or timing of additional requirements for AEP's facilities based on the outcome of these activities.

Regional Haze

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) would address regional haze in federal parks and other protected areas. BART requirements apply to power plants. CAVR will be implemented through SIPs or FIPs. In 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postpones the due date for the next comprehensive SIP revisions until 2021. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

In 2012, the Federal EPA proposed disapproval of a portion of the regional haze SIP in Arkansas and finalized a FIP in 2016. In 2017, Arkansas issued a proposed SIP revision to allow sources to participate in the CSAPR ozone season program in lieu of the source-specific NO_x BART requirements in the FIP, and in 2018, the Federal EPA approved the revision. Arkansas finalized a separate action in 2017 to revise the SO_2 BART determinations and in September 2019, the Federal EPA approved the Arkansas SO_2 BART determinations. SWEPCo's Flint Creek Plant is already in compliance with the applicable requirements.

The Federal EPA also disapproved portions of the Texas regional haze SIP. In 2017, the Federal EPA finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_x regional haze obligations for electric generating units in Texas. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on CSAPR allowance allocations. A challenge to the FIP was filed in the U.S. Court of Appeals for the Fifth Circuit by various intervenors and the case is pending the Federal EPA's reconsideration of the final rule. In August 2018, the Federal EPA proposed to affirm its 2017 FIP approval. Management supports the intrastate trading program contained in the FIP as a compliance alternative to source-specific controls.

Cross-State Air Pollution Rule

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind non-attainment with the 1997 ozone and PM NAAQS. CSAPR relies on 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.

Petitions to review the CSAPR were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2015, the court found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In 2016, the Federal EPA issued a final rule, the CSAPR Update, to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The CSAPR Update significantly reduced ozone season budgets in many states and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. In 2019, the appeals court remanded the CSAPR Update to the Federal EPA because it determined the Federal EPA had not properly considered the attainment dates for downwind areas in establishing its partial remedy, and should have considered whether there were available measures to control emissions from sources other than generating units. Management has complied with the more stringent ozone season budgets while these petitions were pending.

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 established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of non-mercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposed work practice standards for controlling emissions of organic HAPs and dioxin/furans, with compliance required within three years. Management obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

In 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the 2012 final rule. Various intervenors filed petitions for further review in the U.S. Supreme Court.

In 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the MATS rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. In 2016, the Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal and oil-fired units. Petitions for review of the Federal EPA's determination were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal EPA released a revised finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The Federal EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. Therefore, the Federal EPA proposed to retain the current MATS standards without change. The comment period on this proposal ended in April 2019.

Climate Change, CO_2 Regulation and Energy Policy

In 2015, the Federal EPA published the final CO_2 emissions standards for new, modified and reconstructed fossil generating units, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources, known as the Clean Power Plan (CPP).

In 2016, the U.S. Supreme Court issued a stay on the final CPP, including all of the deadlines for submission of initial or final state plans until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. In 2017, the President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance pending reconsideration. In September 2019, following the Federal EPA's finalization of rescission of the CPP and promulgation of the replacement rule, the Court of Appeals for the District of Columbia Circuit dismissed the challenges.

In July 2019, the Federal EPA finalized the Affordable Clean Energy (ACE) rule to replace the CPP with new emission guidelines for regulating CO_2 from existing sources. ACE establishes a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. The final rule applies to generating units that commenced construction prior to January 2014, generate greater than 25 MWs, have a baseload rating above 250 MMBtu per hour and burn coal for more than 10% of the annual average heat input over the preceding three calendar years, with certain exceptions. States must establish standards of performance for each affected facility in terms of pounds of CO_2 emitted per MWh, based on certain heat rate improvement measures and the degree of emission reduction achievable through each applicable measure, together with consideration of certain site-specific factors and the unit's remaining useful life. State plans are required to be submitted within three years, and the Federal EPA has up to two years to review and approve or disapprove the plan and adopt a federal plan. The final ACE rule has been challenged in the courts.

In 2018, the Federal EPA filed a proposed rule revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. Management continues to actively monitor these rulemaking activities.

AEP has taken action to reduce and offset CO_2 emissions from its generating fleet and expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities. 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, purchasing renewable power and broadening AEP System's portfolio of energy efficiency programs.

In September 2019, AEP announced new intermediate and long-term CO_2 emission reduction goals, based on the output of the company's integrated resource plans, which take into account economics, customer demand, grid reliability and resiliency, regulations and the company's current business strategy. The intermediate goal is a 70% reduction from 2000 CO_2 emission levels from AEP generating facilities by 2030; the long-term goal is to surpass an 80% reduction of CO_2 emissions from AEP generating facilities from 2000 levels by 2050. AEP's total estimated CO_2 emissions in 2018 were approximately 69 million metric tons, a 59% reduction from AEP's 2000 CO_2 emissions. AEP has made significant progress in reducing CO_2 emissions from power generation fleet and expect its emissions to continue to decline. AEP's aspirational emissions goal is zero emissions by 2050. Technological advances, including energy storage, will determine how quickly AEP can achieve zero emissions while continuing to provide reliable, affordable power for customers.

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, which could possibly lead to impairment of assets.

Coal Combustion Residual (CCR) Rule

In 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. The rule applies to active CCR landfills and surface impoundments at operating electric utility or independent generation facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four-year implementation period. In 2018, some of AEP's facilities were required to begin monitoring programs to determine if unacceptable groundwater impacts will trigger future corrective measures. Based on additional groundwater data, further studies to design and assess appropriate corrective measures have been undertaken at four facilities. Alternative source demonstrations have been prepared in accordance with the rule at four other facilities.

In a challenge to the final 2015 rule, the parties initially agreed to settle some of the issues. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit addressed or dismissed the remaining issues in its decision vacating and remanding certain provisions of the 2015 rule. The provisions addressed by the court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the court's decision.

Prior to the court's decision, the Federal EPA issued the July 2018 rule that modifies certain compliance deadlines and other requirements in the 2015 rule. In December 2018, challengers filed a motion for partial stay or vacatur of the July 2018 rule. On the same day, the Federal EPA filed a motion for partial remand of the July 2018 rule. The court granted the Federal EPA's motion, and further rulemaking to address the court's decisions is expected to be completed near the end of 2019.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to groundwaters that have a hydrologic connection to a surface water body represent an "unpermitted discharge" under the CWA. Two cases were accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. The Federal EPA opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA permitting requirements for discharges to groundwater, and issued an interpretive statement finding that discharges to groundwater are not subject to NPDES permitting requirements under the CWA. Management is unable to predict the impact of this guidance or the outcome of these cases on AEP's facilities.

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 and conduct any required remedial actions. Closure and post-closure costs have been included in ARO in accordance with the requirements in the final rule. This estimate does not include costs of groundwater remediation, where required. Management will continue to evaluate the rule's impact on operations.

Clean Water Act 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 impinged or entrained in the cooling water. The rule was upheld on review by the U.S. Court of Appeals for the Second Circuit. Compliance timeframes are established by the permit agency through each facility's NPDES permit as those permits are renewed and have been incorporated into permits at several AEP facilities. Additional AEP facilities are reviewing these requirements as their wastewater discharge permits are renewed and making appropriate adjustments to their intake structures.

In 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for generating facilities. The rule established limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. These requirements would be implemented through each facility's wastewater discharge permit. The rule was challenged in the U.S. Court of Appeals for the Fifth Circuit. In 2017, the Federal EPA announced its intent to reconsider and potentially revise the standards for FGD wastewater and bottom ash transport water. The Federal EPA postponed the compliance deadlines for those wastewater categories to be no earlier than 2020, to allow for reconsideration. A revised rule could be proposed later in 2019. In April 2019, the Fifth Circuit vacated the standards for landfill leachate and legacy wastewater, and remanded them to the Federal EPA for reconsideration. Management is assessing technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting.

In 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. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers released a proposed rule to replace the definition in the 2015 rule. The comment period for this proposal ended in April 2019. In September 2019, the Federal EPA announced the final repeal of the 2015 definition of "waters of the United States" and recodification of the regulatory definition that was in place prior to the 2015 rule.

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 AEP Texas and OPCo.
- OPCo purchases energy and capacity at auction to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

The remainder of AEP's activities are presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

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

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

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in millions)			
Vertically Integrated Utilities	$ 437.6	$ 344.2	$ 917.7	$ 852.2
Transmission and Distribution Utilities	133.7	145.2	421.6	384.6
AEP Transmission Holdco	126.1	73.3	404.8	278.4
Generation & Marketing	90.0	5.3	139.5	62.3
Corporate and Other	(53.9)	9.6	(116.0)	(17.1)
Earnings Attributable to AEP Common Shareholders	$ 733.5	$ 577.6	$ 1,767.6	$ 1,560.4

AEP CONSOLIDATED

Third Quarter of 2019 Compared to Third Quarter of 2018

Earnings Attributable to AEP Common Shareholders increased from $578 million in 2018 to $734 million in 2019 primarily due to:

- Favorable rate proceedings in AEP's various jurisdictions.
- An increase in weather-related usage.
- An increase in transmission investment, which resulted in higher revenues and income.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Earnings Attributable to AEP Common Shareholders increased from $1.6 billion in 2018 to $1.8 billion in 2019 primarily due to:

- Favorable rate proceedings in AEP's various jurisdictions.
- An increase in transmission investment, which resulted in higher revenues and income.

These increases were partially offset by:

- A decrease in weather-related usage.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in millions)			
Revenues	$ 2,645.5	$ 2,636.7	$ 7,172.6	$ 7,393.7
Fuel and Purchased Electricity	874.2	1,034.6	2,430.2	2,700.4
Gross Margin	1,771.3	1,602.1	4,742.4	4,693.3
Other Operation and Maintenance	742.9	753.7	2,117.1	2,197.5
Depreciation and Amortization	364.3	340.1	1,079.6	966.1
Taxes Other Than Income Taxes	117.9	108.8	347.1	326.4
Operating Income	546.2	399.5	1,198.6	1,203.3
Other Income	0.9	4.1	4.4	14.2
Allowance for Equity Funds Used During Construction	12.2	9.3	38.9	24.0
Non-Service Cost Components of Net Periodic Benefit Cost	17.0	18.0	50.8	53.7
Interest Expense	(140.6)	(149.2)	(422.6)	(428.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings	435.7	281.7	870.1	867.2
Income Tax Expense (Benefit)	(1.9)	(63.1)	(48.4)	12.9
Equity Earnings of Unconsolidated Subsidiary	0.8	0.8	2.3	2.0
Net Income	438.4	345.6	920.8	856.3
Net Income Attributable to Noncontrolling Interests	0.8	1.4	3.1	4.1
Earnings Attributable to AEP Common Shareholders	$ 437.6	$ 344.2	$ 917.7	$ 852.2

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in millions of KWhs)			
Retail:				
Residential	9,254	8,988	24,785	26,105
Commercial	6,840	6,723	18,183	18,699
Industrial	9,123	9,107	26,533	26,757
Miscellaneous	641	621	1,734	1,762
Total Retail (a)	25,858	25,439	71,235	73,323
Wholesale (b)	5,864	6,432	16,494	17,156
Total KWhs	31,722	31,871	87,729	90,479

(a) 2018 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

(b) Includes Off-system Sales, municipalities and cooperatives, unit power and other wholesale customers.

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,670	1,844
Normal – Heating (b)	5	5	1,742	1,745
Actual – Cooling (c)	937	878	1,316	1,364
Normal – Cooling (b)	732	730	1,070	1,063
Western Region				
Actual – Heating (a)	—	—	967	974
Normal – Heating (b)	1	1	902	908
Actual – Cooling (c)	1,572	1,443	2,234	2,380
Normal – Cooling (b)	1,402	1,402	2,129	2,121

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

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Third Quarter of 2018	$	344.2
Changes in Gross Margin:		
Retail Margins		145.1
Margins from Off-system Sales		(0.9)
Transmission Revenues		23.8
Other Revenues		1.2
Total Change in Gross Margin		169.2
Changes in Expenses and Other:		
Other Operation and Maintenance		10.8
Depreciation and Amortization		(24.2)
Taxes Other Than Income Taxes		(9.1)
Other Income		(3.2)
Allowance for Equity Funds Used During Construction		2.9
Non-Service Cost Components of Net Periodic Pension Cost		(1.0)
Interest Expense		8.6
Total Change in Expenses and Other		(15.2)
Income Tax Expense (Benefit)		(61.2)
Net Income Attributable to Noncontrolling Interests		0.6
Third Quarter of 2019	$	437.6

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 $145 million primarily due to the following:
  - A $91 million increase at APCo and WPCo due to a 2018 reduction in the deferred fuel under recovery balance as a result of the 2018 West Virginia Tax Reform settlement. This increase was partially offset in Income Tax Expense (Benefit) below.
  - A $23 million increase in weather-related usage primarily in the residential class.
  - A $15 million increase at APCo in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $10 million increase due to 2018 Virginia legislation which increased non-recoverable fuel expense at APCo in the prior year.
  - A $4 million increase in weather-normalized retail margins across all classes.
  - The effect of rate proceedings in AEP's service territories which included:
    - A $19 million increase from rate proceedings at I&M. This increase was partially offset in other expense items below.
    - A $14 million increase at PSO due to new base rates implemented in April 2019.
    - A $10 million increase at APCo and WPCo due to revenue primarily from rate riders in West Virginia. This increase was offset in other expense items below.
    - An $8 million increase related to rider revenues at I&M, primarily due to the timing of the Indiana PJM/OSS rider recovery. This increase was partially offset in other expense items below.
    - A $7 million increase at APCo and WPCo due to base rate increases in West Virginia implemented in March 2019.

  These increases were partially offset by:
  - A $74 million decrease due to customer refunds related to Tax Reform. This decrease was partially offset in Income Tax Expense (Benefit) below.

- **Transmission Revenues** increased $24 million primarily due to the following:
  - A $16 million increase due to SPP provisions for refund recorded in 2018.
  - A $16 million increase primarily due to 2018 PJM provisions for refunds mainly at APCo.

  These increases were partially offset by:
  - An $8 million decrease primarily due to a reduction in SPP Base Plan Funding revenues and a decrease in nonaffiliated transmission services.

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

- **Other Operation and Maintenance** expenses decreased $11 million primarily due to the following:
  - A $40 million decrease at APCo and WPCo due to the extinguishment of certain regulatory asset balances as agreed to within the 2018 West Virginia Tax Reform settlement.
  - A $12 million decrease in planned plant outage and maintenance expenses primarily at APCo and I&M.
  - A $9 million decrease due to Wind Catcher Project expenses incurred in 2018 for SWEPCo and PSO.
  - A $3 million decrease in recoverable expenses primarily associated with Energy Efficiency/Demand Response and storm expenses fully recovered in rate riders/trackers within Gross Margin above.

  These decreases were partially offset by:
  - A $45 million increase due to PJM transmission services including the annual formula rate true-up.
  - An $8 million increase due to the modification of the NSR consent decree impacting I&M and AEGCo.
  - A $2 million increase due to North Central Wind Energy Facilities expenses for SWEPCo and PSO.
- **Depreciation and Amortization** expenses increased $24 million primarily due to a higher depreciable base and increased depreciation rates approved at APCo, I&M and SWEPCo.
- **Taxes Other Than Income Taxes** increased $9 million primarily due to the following:
  - A $5 million increase in property taxes driven by an increase in utility plant.
  - A $5 million increase in West Virginia business and occupational taxes at APCo and WPCo.
- **Interest Expense** decreased $9 million primarily due to lower interest rates on outstanding long-term debt at I&M and SWEPCo.
- **Income Tax Expense (Benefit)** increased $61 million primarily due to the one time recognition of $86 million of additional amortization of Excess ADIT as a result of the West Virginia Tax Reform order received in the third quarter of 2018. The additional excess amortization from the West Virginia Tax Reform order was partially offset in Retail Margins and Other Operation and Maintenance expenses above.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2018	$	852.2
Changes in Gross Margin:		
Retail Margins		75.4
Margins from Off-system Sales		(10.4)
Transmission Revenues		(16.4)
Other Revenues		0.5
Total Change in Gross Margin		49.1
Changes in Expenses and Other:		
Other Operation and Maintenance		80.4
Depreciation and Amortization		(113.5)
Taxes Other Than Income Taxes		(20.7)
Other Income		(9.8)
Allowance for Equity Funds Used During Construction		14.9
Non-Service Cost Components of Net Periodic Pension Cost		(2.9)
Interest Expense		5.4
Total Change in Expenses and Other		(46.2)
Income Tax Expense (Benefit)		61.3
Equity Earnings of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interests		1.0
Nine Months Ended September 30, 2019	$	917.7

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 $75 million primarily due to the following:
  - A $91 million increase at APCo and WPCo due to a 2018 reduction in the deferred fuel under recovery balance as a result of the 2018 West Virginia Tax Reform settlement. This increase was partially offset in Income Tax Expense (Benefit) below.
  - A $12 million increase at APCo in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $10 million increase due to 2018 Virginia legislation which increased non-recoverable fuel expense at APCo in the prior year.
  - A $6 million decrease at I&M in fuel-related expenses due to timing of recovery for fuel and other variable production costs related to wholesale contracts.
  - The effect of rate proceedings in AEP's service territories which included:
    - A $94 million increase from rate proceedings at I&M, inclusive of a $30 million decrease due to the impact of Tax Reform. This increase was partially offset in other expense items below.
    - A $35 million increase at PSO due to new base rates implemented in April 2019 and March 2018.
    - A $21 million increase related to rider revenues at I&M, primarily due to the timing of the Indiana PJM/OSS rider recovery. This increase was partially offset in other expense items below.
    - A $17 million increase at APCo and WPCo primarily due to revenue from rate riders in West Virginia. This increase was offset in other expense items below.
    - A $14 million increase at APCo and WPCo due to base rate increases in West Virginia implemented in March 2019.

- A $7 million increase at SWEPCo primarily due to rider and base rate revenue increases in Louisiana. The increase in rider rates had increases in other expense items below.
    - A $4 million increase in rider revenues at KPCo offset in other expense items below.

  These increases were partially offset by:
  - A $117 million decrease due to customer refunds related to Tax Reform. This decrease was partially offset in Income Tax Expense (Benefit) below.
  - A $73 million decrease in weather-related usage across all regions primarily in the residential class.
  - A $67 million decrease in weather-normalized retail margins across all classes.
- **Margins from Off-system Sales** decreased $10 million primarily due to mid-year 2018 changes in the OSS sharing mechanism at I&M.
- **Transmission Revenues** decreased $16 million primarily due to the following:
  - A $40 million decrease in SWEPCo's annual SPP Transmission formula rate true-up.
  - A $12 million decrease primarily due to I&M's annual PJM Transmission formula rate true-up.
  - An $11 million decrease primarily due to a reduction in SPP Base Plan Funding revenues.

  These decreases were partially offset by:
  - A $36 million increase primarily due to 2018 PJM provisions for refund mainly at APCo.
  - A $16 million increase due to a provision for refund recorded at PSO and SWEPCo in 2018 related to certain transmission assets that management believes should not have been included in the SPP formula rate.

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

- **Other Operation and Maintenance** expenses decreased $80 million primarily due to the following:
  - A $56 million decrease due to SPP transmission services including the annual formula rate true-up.
  - A $47 million decrease in planned plant outage and maintenance expenses primarily for I&M, APCo, SWEPCo and KPCo.
  - A $40 million decrease due to Wind Catcher Project expenses incurred in 2018 for SWEPCo and PSO.
  - A $40 million decrease at APCo and WPCo due to the extinguishment of certain regulatory asset balances as agreed to within the 2018 West Virginia Tax Reform settlement.
  - A $25 million decrease in recoverable expenses primarily associated with Energy Efficiency/Demand Response and storm expenses fully recovered in rate riders/trackers within Gross Margin above.
  - A $10 million decrease in expense at APCo due to lower current year amortization of certain regulatory assets that were extinguished in August 2018 as agreed to within the 2018 West Virginia Tax Reform settlement.
  - A $9 million decrease in estimated expense for claims related to asbestos exposure.

  These decreases were partially offset by:
  - A $92 million increase due to PJM transmission services including the annual formula rate true-up.
  - A $23 million increase in employee-related expenses.
  - A $13 million increase at APCo due to 2019 contributions to benefit low income West Virginia residential customers as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - An $8 million increase in storm-related expenses primarily at SWEPCo.
  - An $8 million increase due to the modification of the NSR consent decree impacting I&M and AEGCo.
  - A $5 million increase due to North Central Wind Energy Facilities expenses for SWEPCo and PSO.
- **Depreciation and Amortization** expenses increased $114 million primarily due to a higher depreciable base and increased depreciation rates approved at I&M, APCo, SWEPCo and PSO.
- **Taxes Other Than Income Taxes** increased $21 million primarily due to the following:
  - A $14 million increase in property taxes driven by an increase in utility plant.
  - A $9 million increase at APCo and WPCo in West Virginia business and occupational taxes.
- **Other Income** decreased $10 million primarily due to a decrease in carrying charges for certain riders at I&M.
- **Allowance for Equity Funds Used During Construction** increased $15 million primarily due to the following:
  - A $10 million increase primarily due to various increases in equity rates at I&M, APCo and PSO and increased projects at I&M.
  - A $3 million increase due to recent FERC audit findings.
  - A $2 million increase due to the FERC's approval of a settlement agreement.

- **Interest Expense** decreased $5 million primarily due to the following:
  - A $16 million decrease due to lower interest rates on outstanding long-term debt at I&M and SWEPCo.

  This decrease was partially offset by:
  - An $11 million increase primarily due to higher long-term debt balances mainly at APCo and PSO.
- **Income Tax Expense (Benefit)** decreased $61 million primarily due to additional amortization of Excess ADIT as a result of finalized rate orders. The excess amortization is partially offset within Gross Margin and Other Operation and Maintenance above.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in millions)			
Revenues	$ 1,186.6	$ 1,211.5	$ 3,454.3	$ 3,510.9
Purchased Electricity	210.1	218.7	603.5	660.0
Amortization of Generation Deferrals	8.8	56.9	65.3	171.9
Gross Margin	967.7	935.9	2,785.5	2,679.0
Other Operation and Maintenance	405.8	420.4	1,222.1	1,152.1
Depreciation and Amortization	209.3	201.4	586.4	558.4
Taxes Other Than Income Taxes	151.8	143.2	437.2	413.2
Operating Income	200.8	170.9	539.8	555.3
Interest and Investment Income	1.1	1.3	4.2	2.6
Carrying Costs Income	0.3	0.2	0.7	1.5
Allowance for Equity Funds Used During Construction	9.8	7.8	22.3	23.0
Non-Service Cost Components of Net Periodic Benefit Cost	7.7	8.3	22.8	24.6
Interest Expense	(63.6)	(63.5)	(170.8)	(185.6)
Income Before Income Tax Expense (Benefit)	156.1	125.0	419.0	421.4
Income Tax Expense (Benefit)	22.4	(20.2)	(2.6)	36.8
Net Income	133.7	145.2	421.6	384.6
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 133.7	$ 145.2	$ 421.6	$ 384.6

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in millions of KWhs)			
Retail:				
Residential	8,268	7,948	20,614	21,154
Commercial	7,219	6,958	19,069	19,061
Industrial	5,857	5,904	17,492	17,772
Miscellaneous	223	209	595	574
Total Retail (a)(b)	21,567	21,019	57,770	58,561
Wholesale (c)	453	634	1,531	1,835
Total KWhs	22,020	21,653	59,301	60,396

(a) 2018 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(b) Represents energy delivered to distribution customers.
(c) Primarily Ohio's contractually obligated purchases of OVEC power sold to PJM.

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

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

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2019	**2018**	**2019**	**2018**
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	2,006	2,158
Normal – Heating (b)	6	6	2,072	2,076
Actual – Cooling (c)	872	864	1,176	1,322
Normal – Cooling (b)	672	670	973	964
Western Region				
Actual – Heating (a)	—	—	180	234
Normal – Heating (b)	—	—	190	194
Actual – Cooling (d)	1,587	1,424	2,679	2,612
Normal – Cooling (b)	1,368	1,367	2,425	2,413

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

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Third Quarter of 2018	$	145.2
Changes in Gross Margin:		
Retail Margins		2.2
Margins from Off-system Sales		4.6
Transmission Revenues		17.3
Other Revenues		7.7
Total Change in Gross Margin		31.8
Changes in Expenses and Other:		
Other Operation and Maintenance		14.6
Depreciation and Amortization		(7.9)
Taxes Other Than Income Taxes		(8.6)
Interest and Investment Income		(0.2)
Carrying Costs Income		0.1
Allowance for Equity Funds Used During Construction		2.0
Non-Service Cost Components of Net Periodic Benefit Cost		(0.6)
Interest Expense		(0.1)
Total Change in Expenses and Other		(0.7)
Income Tax Expense (Benefit)		(42.6)
Third Quarter of 2019	$	133.7

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 $2 million primarily due to the following:
  - A $27 million net increase primarily due to 2018 adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement and changes in tax riders. This increase was partially offset in Income Tax Expense (Benefit) below.
  - A $12 million increase due to the recovery of higher current year losses from a power contract with OVEC in Ohio. This increase was offset in Margins from Off-system Sales below.
  - A $9 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.
  - An $8 million increase in weather-related usage in Texas primarily due to an 11% increase in cooling degree days.
  - A $6 million increase in weather-normalized margins primarily in the residential class.
  - A $4 million increase in Ohio rider revenues associated with the DIR. This decrease was partially offset in other expense items below.
  - A $3 million increase in Ohio Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.

  These increases were partially offset by:
  - A $28 million net decrease in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $13 million decrease in Ohio Deferred Asset Phase-In-Recovery Rider revenues which ended in the second quarter of 2019. This decrease was offset in Depreciation and Amortization expenses below.
  - An $8 million net decrease in margin in Ohio for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.

    - A $6 million decrease in revenues associated with a vegetation management rider in Ohio. This decrease was offset in Other Operation and Maintenance expenses below.
    - A $6 million net decrease in margin in Ohio for the Phase-In-Recovery Rider including associated amortizations which ended in the first quarter of 2019.
    - A $6 million decrease in affiliated PPA capacity revenues in Texas. This decrease was offset in Margins from Off-system Sales below.
- **Margins from Off-system Sales** increased $5 million primarily due to the following:
    - A $17 million increase due to higher affiliated PPA revenues in Texas. This increase was partially offset by in Other Operation and Maintenance expenses below.

    This increase was partially offset by:
    - A $12 million decrease primarily due to higher current year losses from a power contract with OVEC and lower deferrals as a result of the OVEC PPA rider in Ohio. This decrease was offset in Retail Margins above.
- **Transmission Revenues** increased $17 million primarily due to the recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $8 million primarily due to securitization revenue related to Transition Funding. This decrease was offset below in Depreciation and Amortization expenses and in Interest Expense.

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

- **Other Operation and Maintenance** expenses decreased $15 million primarily due to the following:
    - A $29 million decrease in transmission expenses that were fully recovered in rate riders/trackers in Gross Margin above.
    - A $4 million decrease due to higher charitable contributions in 2018 in Ohio.

    These decreases were partially offset by:
    - A $16 million increase in affiliated PPA expenses in Texas. This increase was offset by an increase in Margins from Off-system Sales above.
    - A $12 million increase in PJM expenses primarily related to the annual formula rate true-up.
- **Depreciation and Amortization** expenses increased $8 million primarily due to the following:
    - A $15 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
    - A $7 million increase in securitization amortizations primarily related to Transition Funding. This increase was offset in Other Revenues above and in Interest Expense below.

    These increases were partially offset by:
    - An $8 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider in Ohio which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.
    - A $6 million decrease in Ohio recoverable DIR depreciation expense. This decrease was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $9 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Interest Expense** was unchanged primarily due to the following:
    - A $5 million decrease due to the deferral of previously recorded interest expense approved for recovery as a result of the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.
    - A $3 million decrease in expense related to Transition Funding Securitization assets. This decrease was offset in Other Revenues and Depreciation and Amortization expenses above.

    These decreases were partially offset by:
    - A $6 million increase due to higher long-term debt balances.
- **Income Tax Expense (Benefit)** decreased $43 million primarily due to a one-time recognition of increased amortization of Excess ADIT not subject to normalization requirements as a result of the 2018 Ohio Tax Reform Settlement. This increase was partially offset in Retail Margins above.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2018	$	384.6
Changes in Gross Margin:		
Retail Margins		(9.3)
Margins from Off-system Sales		38.5
Transmission Revenues		68.2
Other Revenues		9.1
Total Change in Gross Margin		106.5
Changes in Expenses and Other:		
Other Operation and Maintenance		(70.0)
Depreciation and Amortization		(28.0)
Taxes Other Than Income Taxes		(24.0)
Interest and Investment Income		1.6
Carrying Costs Income		(0.8)
Allowance for Equity Funds Used During Construction		(0.7)
Non-Service Cost Components of Net Periodic Benefit Cost		(1.8)
Interest Expense		14.8
Total Change in Expenses and Other		(108.9)
Income Tax Expense (Benefit)		39.4
Nine Months Ended September 30, 2019	$	421.6

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** decreased $9 million primarily due to the following:
  - A $71 million net decrease in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - An $18 million decrease in revenues associated with a vegetation management rider in Ohio. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $17 million decrease in affiliated PPA capacity revenues in Texas. This decrease was offset in Margins from Off-system Sales below.
  - A $16 million net decrease in margin in Ohio for the Phase-In-Recovery Rider including associated amortizations which ended in the first quarter of 2019.
  - A $13 million decrease in Ohio Deferred Asset Phase-In-Recovery Rider revenues which ended in the second quarter of 2019. This decrease was offset in Depreciation and Amortization expenses below.
  - A $12 million net decrease in margin in Ohio for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $7 million decrease in Texas revenues associated with the Transmission Cost Recovery Factor revenue rider. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $5 million decrease in weather-related usage in Texas primarily due to a 23% decrease in heating degree days partially offset by a 3% increase in cooling degree days.
  - A $4 million decrease in Ohio rider revenues associated with the DIR. This decrease was partially offset in other expense items below.

  These decreases were partially offset by:
  - A $58 million increase due to a reversal of a regulatory provision in Ohio.

- A $33 million net increase due to 2018 adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement and changes in tax riders. This increase was partially offset in Income Tax Expense (Benefit) below.
- A $31 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.
- A $21 million increase due to the recovery of higher current year losses from a power contract with OVEC in Ohio. This increase was offset in Margins from Off-system Sales below.
- A $9 million increase in Ohio Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset in Other Operation and Maintenance expenses below.

- **Margins from Off-system Sales** increased $39 million primarily due to the following:
  - A $59 million increase due to higher affiliated PPA revenues in Texas. This increase was partially offset in Other Operation and Maintenance expenses below.

  This increase was partially offset by:
  - A $21 million decrease primarily due to higher current year losses from a power contract with OVEC as a result of the OVEC PPA rider in Ohio. This decrease was offset in Retail Margins above.
- **Transmission Revenues** increased $68 million primarily due to the following:
  - A $62 million increase primarily due to recovery of increased transmission investment in ERCOT.
  - A $6 million increase in Ohio primarily due to 2018 provisions for refunds.
- **Other Revenues** increased $9 million primarily due to distribution connection fees and pole attachment revenues.

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

- **Other Operation and Maintenance** expenses increased $70 million primarily due to the following:
  - A $64 million increase in expense due to the partial amortization of the Texas Storm Cost Securitization regulatory asset as a result of the final PUCT order in the Texas Storm Cost Case. This increase was offset in Income Tax Expense (Benefit) below.
  - A $57 million increase in PJM expenses primarily related to the annual formula rate true-up.
  - A $49 million increase in affiliated PPA expenses in Texas. This increase was offset in Margins from Off-system Sales above.

  These increases were partially offset by:
  - A $93 million decrease in transmission expenses that were fully recovered in rate riders/trackers in Gross Margin above.
- **Depreciation and Amortization** expenses increased $28 million primarily due to the following:
  - A $51 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $9 million increase in securitization amortizations primarily related to Transition Funding. This increase was offset in Other Revenues above and in Interest Expense below.
  - A $7 million increase in depreciation expense related to the Oklaunion Power Station.

  These increases were partially offset by:
  - A $30 million decrease in Ohio recoverable DIR depreciation expense. This decrease was partially offset in Retail Margins above.
  - An $11 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $24 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Interest Expense** decreased $15 million primarily due to the following:
  - A $21 million decrease due to the deferral of previously recorded interest expense approved for recovery as a result of the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.
  - An $8 million decrease in expense related to Transition Funding Securitization assets. This decrease was offset in Other Revenues and Depreciation and Amortization expenses above.

  These decreases were partially offset by:
  - A $14 million increase due to higher long-term debt balances.

- **Income Tax Expense (Benefit)** decreased $39 million primarily due to the following:
  - A $64 million decrease due to the amortization of Excess ADIT not subject to normalization requirements as approved in the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019. This increase was offset in Other Operation and Maintenance expenses above.

  This decrease was partially offset by:
  - A $30 million increase primarily due to a one-time recognition of increased amortization of Excess ADIT not subject to normalization requirements as a result of the 2018 Ohio Tax Reform Settlement. This increase was partially offset in Retail Margins above.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended September 30, 2019		Three Months Ended September 30, 2018		Nine Months Ended September 30, 2019		Nine Months Ended September 30, 2018	
	(in millions)							
Transmission Revenues	$	273.0	$	187.2	$	808.3	$	605.2
Other Operation and Maintenance		31.8		30.9		77.0		76.2
Depreciation and Amortization		47.3		34.4		133.7		100.0
Taxes Other Than Income Taxes		44.3		36.3		130.4		106.5
Operating Income		149.6		85.6		467.2		322.5
Other Income		0.8		0.4		2.3		1.1
Allowance for Equity Funds Used During Construction		21.0		13.8		61.1		45.4
Non-Service Cost Components of Net Periodic Benefit Cost		0.7		0.7		2.0		2.1
Interest Expense		(27.8)		(24.2)		(73.8)		(66.8)
Income Before Income Tax Expense and Equity Earnings		144.3		76.3		458.8		304.3
Income Tax Expense		35.4		19.2		105.7		75.0
Equity Earnings of Unconsolidated Subsidiary		18.1		17.1		54.5		51.6
Net Income		127.0		74.2		407.6		280.9
Net Income Attributable to Noncontrolling Interests		0.9		0.9		2.8		2.5
Earnings Attributable to AEP Common Shareholders	$	126.1	$	73.3	$	404.8	$	278.4

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	September 30, 2019		September 30, 2018	
	(in millions)			
Plant in Service	$	7,796.9	$	6,307.3
Construction Work in Progress		1,903.4		1,823.0
Accumulated Depreciation and Amortization		383.7		244.3
Total Transmission Property, Net	$	9,316.6	$	7,886.0

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2018	$	73.3
Changes in Transmission Revenues:		
Transmission Revenues		85.8
Total Change in Transmission Revenues		85.8
Changes in Expenses and Other:		
Other Operation and Maintenance		(0.9)
Depreciation and Amortization		(12.9)
Taxes Other Than Income Taxes		(8.0)
Other Income		0.4
Allowance for Equity Funds Used During Construction		7.2
Interest Expense		(3.6)
Total Change in Expenses and Other		(17.8)
Income Tax Expense		(16.2)
Equity Earnings of Unconsolidated Subsidiary		1.0
Third Quarter of 2019	$	126.1

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

- **Transmission Revenues** increased $86 million primarily due to continued investment in transmission assets.

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

- **Depreciation and Amortization** expenses increased $13 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $7 million primarily due to higher CWIP balances.
- **Interest Expense** increased $4 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $16 million primarily due to higher pretax book income.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2018	$	278.4
Changes in Transmission Revenues:		
Transmission Revenues		203.1
Total Change in Transmission Revenues		203.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(0.8)
Depreciation and Amortization		(33.7)
Taxes Other Than Income Taxes		(23.9)
Other Income		1.2
Allowance for Equity Funds Used During Construction		15.7
Non-Service Cost Components of Net Periodic Pension Cost		(0.1)
Interest Expense		(7.0)
Total Change in Expenses and Other		(48.6)
Income Tax Expense		(30.7)
Equity Earnings of Unconsolidated Subsidiary		2.9
Net Income Attributable to Noncontrolling Interests		(0.3)
Nine Months Ended September 30, 2019	$	404.8

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

- **Transmission Revenues** increased $203 million primarily due to continued investment in transmission assets.

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

- **Depreciation and Amortization** expenses increased $34 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $24 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $16 million primarily due to the following:
  - A $13 million increase primarily due to higher CWIP balances.
  - A $12 million increase due to the FERC's approval of a settlement agreement.

  These increases were partially offset by:
  - A $13 million decrease due to recent FERC audit findings.
- **Interest Expense** increased $7 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $31 million primarily due to higher pretax book income with a partial offset due to the FERC's approval of a settlement agreement.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in millions)			
Revenues	$ 533.7	$ 521.6	$ 1,428.2	$ 1,487.4
Fuel, Purchased Electricity and Other	403.8	405.0	1,117.8	1,167.8
Gross Margin	129.9	116.6	310.4	319.6
Other Operation and Maintenance	44.0	68.2	158.0	192.6
Asset Impairments and Other Related Charges	—	35.0	—	35.0
Depreciation and Amortization	20.6	12.0	49.1	26.4
Taxes Other Than Income Taxes	4.4	3.7	11.8	10.3
Operating Income (Loss)	60.9	(2.3)	91.5	55.3
Interest and Investment Income	1.9	3.6	6.0	9.9
Non-Service Cost Components of Net Periodic Benefit Cost	3.8	3.8	11.2	11.5
Interest Expense	(10.5)	(3.8)	(21.5)	(11.7)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	56.1	1.3	87.2	65.0
Income Tax Expense (Benefit)	(36.4)	(3.6)	(51.8)	3.7
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(3.8)	0.2	(5.9)	0.5
Net Income	88.7	5.1	133.1	61.8
Net Loss Attributable to Noncontrolling Interests	(1.3)	(0.2)	(6.4)	(0.5)
Earnings Attributable to AEP Common Shareholders	$ 90.0	$ 5.3	$ 139.5	$ 62.3

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in millions of MWhs)			
Fuel Type:				
Coal	2	4	4	10
Renewables	1	—	2	1
Total MWhs	3	4	6	11

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2018	$	5.3
Changes in Gross Margin:		
Generation		(10.6)
Retail, Trading and Marketing		12.9
Other Revenues		11.0
Total Change in Gross Margin		13.3
Changes in Expenses and Other:		
Other Operation and Maintenance		24.2
Asset Impairments and Other Related Charges		35.0
Depreciation and Amortization		(8.6)
Taxes Other Than Income Taxes		(0.7)
Interest and Investment Income		(1.7)
Interest Expense		(6.7)
Total Change in Expenses and Other		41.5
Income Tax Expense (Benefit)		32.8
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(4.0)
Net Loss Attributable to Noncontrolling Interests		1.1
Third Quarter of 2019	$	90.0

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, purchased electricity and certain cost of service for retail operations were as follows:

- **Generation** decreased $11 million primarily due to reduction in capacity revenues in 2019 partially due to the retirement of Conesville Units 5 & 6 in 2019.
- **Retail, Trading and Marketing** increased $13 million due to higher trading and marketing activity in 2019.
- **Other Revenues** increased $11 million primarily due to the Sempra Renewables LLC acquisition and other renewable projects placed in-service.

Expenses and Other, Income Tax Expense (Benefit) and Net Loss Attributable to Noncontrolling Interests changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $24 million due to the following:
  - A $20 million decrease due to the retirement of Conesville Units 5 & 6 in 2019.
  - An $11 million decrease due to the retirement of Stuart Plant in June of 2018.

  These decreases were partially offset by:
  - A $7 million increase due to the acquisitions of Sempra Renewables LLC and Santa Rita East.
- **Asset Impairment and Other Related Charges** decreased $35 million due to the impairment of Racine in the third quarter of 2018.
- **Depreciation and Amortization** expenses increased $9 million due to a higher depreciable base from increased investments in wind farms and renewable energy sources.
- **Interest Expense** increased $7 million primarily due to increased borrowing costs related to the Sempra Renewables LLC acquisition.
- **Income Tax Expense (Benefit)** decreased $33 million primarily due to an increase in projected renewable PTC primarily driven by the Sempra Renewables LLC acquisition partially offset by an increase in pretax book income.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** decreased $4 million primarily due to the Sempra Renewables LLC acquisition.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Nine Months Ended September 30, 2018	$	62.3
Changes in Gross Margin:		
Generation		(55.1)
Retail, Trading and Marketing		28.0
Other Revenues		17.9
Total Change in Gross Margin		(9.2)
Changes in Expenses and Other:		
Other Operation and Maintenance		34.6
Asset Impairments and Other Related Charges		35.0
Depreciation and Amortization		(22.7)
Taxes Other Than Income Taxes		(1.5)
Interest and Investment Income		(3.9)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(9.8)
Total Change in Expenses and Other		31.4
Income Tax Expense (Benefit)		55.5
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(6.4)
Net Loss Attributable to Noncontrolling Interests		5.9
Nine Months Ended September 30, 2019	$	139.5

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 $55 million primarily due to the reduction of capacity revenues and energy margins in 2019, a reduction in revenues due to the retirement of the Stuart Plant in 2018 and the retirement of Conesville Units 5 & 6 in 2019.
- **Retail, Trading and Marketing** increased $28 million primarily due to higher retail margins due to lower market costs and higher delivered volumes and higher marketing activity in 2019.
- **Other Revenues** increased $18 million primarily due to the Sempra Renewables LLC acquisition and other renewable projects placed in-service.

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

- **Other Operation and Maintenance** expenses decreased $35 million due to the following:
  - A $40 million decrease due to the retirement of Conesville Units 5 & 6 in 2019.
  - A $15 million decrease due to the retirement of Stuart Plant in June of 2018.

  These decreases were partially offset by:
  - A $20 million increase due to the acquisitions of Sempra Renewables LLC and Santa Rita East.
- **Asset Impairment and Other Related Charges** decreased $35 million due to the impairment of Racine in the third quarter of 2018.
- **Depreciation and Amortization** expenses increased $23 million due to a higher depreciable base from increased investments in wind farms and renewable energy sources.
- **Interest and Investment Income** decreased $4 million primarily due to a reduction in Advances to Affiliates which was driven by a dividend payment made to Parent in 2018.

- **Interest Expense** increased $10 million primarily due to increased borrowing costs related to the Sempra Renewables LLC acquisition.
- **Income Tax Expense (Benefit)** decreased $56 million primarily due to an increase in projected renewable PTC primarily driven by the Sempra Renewables LLC acquisition partially offset by an increase in pretax book income.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** decreased $6 million primarily due to the Sempra Renewables LLC acquisition.
- **Net Loss Attributable to Noncontrolling Interests** increased $6 million primarily due to the Sempra Renewables LLC acquisition.

CORPORATE AND OTHER

Third Quarter of 2019 Compared to Third Quarter of 2018

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from $10 million in 2018 to a loss of $54 million in 2019 primarily due to:

- A $40 million increase in income tax expense due to an increase in consolidating tax adjustments. This increase is offset primarily within the Generation & Marketing segment.
- A $20 million increase in interest expense as a result of increased debt outstanding.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $17 million in 2018 to a loss of $116 million in 2019 primarily due to:

- A $63 million increase in income tax expense primarily due to the following:
  - A $30 million increase due to an increase in consolidating tax adjustments. This increase is offset primarily within the Generation & Marketing segment.
  - An $18 million increase related to the enactment of the Kentucky state tax legislation in the second quarter of 2018.
  - A $10 million increase due to an increase in the allocation of the parent company loss benefit due to the tax sharing agreement with AEP Subsidiaries.
  - A $5 million increase due to the current year revaluation of AEP’s state deferred tax liability as a result of the state income tax filing requirement in Kansas associated with the Sempra Renewables LLC acquisition.
- A $55 million increase in interest expense as a result of increased debt outstanding.
- A $5 million impairment of an equity investment and related assets in 2019.

These items were partially offset by:

- A $20 million impairment of an equity investment and related assets in 2018.
- An $8 million increase in interest income due to a higher return on investments held by EIS.

AEP SYSTEM INCOME TAXES

Third Quarter of 2019 Compared to Third Quarter of 2018

Income Tax Expense (Benefit) increased $121 million primarily due to the prior year effects of the discrete impact of $124 million of amortization of Excess ADIT not subject to normalization requirements as a result of the Ohio and West Virginia Tax Reform Orders received in the third quarter of 2018.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Income Tax Expense (Benefit) decreased $63 million primarily due to increased amortization of Excess ADIT not subject to normalization requirements as a result of finalized Tax Reform orders and an increase in projected renewable income tax credits.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2019		December 31, 2018	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 25,881.2	53.5%	$ 23,346.7	52.7%
Short-term Debt	2,510.0	5.2	1,910.0	4.3
Total Debt	28,391.2	58.7	25,256.7	57.0
AEP Common Equity	19,716.4	40.7	19,028.4	42.9
Noncontrolling Interests	281.3	0.6	31.0	0.1
Total Debt and Equity Capitalization	$ 48,388.9	100.0%	$ 44,316.1	100.0%

AEP's ratio of debt-to-total capital increased from 57% as of December 31, 2018 to 58.7% as of September 30, 2019 primarily due to an increase in debt to support distribution, transmission and renewable investment growth.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of September 30, 2019, AEP had a $4 billion revolving credit facility to support its commercial paper program. 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, leasing agreements, hybrid securities or common stock.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of September 30, 2019, available liquidity was approximately $2.6 billion as illustrated in the table below:

	Amount	Maturity
Commercial Paper Backup:	(in millions)	
Revolving Credit Facility	$ 4,000.0	June 2022
Cash and Cash Equivalents	348.8	
Total Liquidity Sources	4,348.8	
Less: AEP Commercial Paper Outstanding	1,760.0	
Net Available Liquidity	$ 2,588.8	

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. The maximum amount of commercial paper outstanding during the first nine months of 2019 was $2.2 billion. The weighted-average interest rate for AEP's commercial paper during 2019 was 2.66%.

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 on behalf of subsidiaries under six uncommitted facilities totaling $405 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2019 was $204 million with maturities ranging from October 2019 to October 2020.

Securitized Accounts Receivables

AEP’s receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in July 2021.

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 agreement excludes securitization bonds and debt of AEP Credit. As of September 30, 2019, this contractually-defined percentage was 55.3%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP’s payment obligations, or the obligations of certain of AEP’s major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP’s non-exchange-traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP’s non-exchange-traded commodity contracts would not cause an event of default under its credit agreements.

The revolving credit facility does not permit the lenders to refuse a draw on 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.

Equity Units

In March 2019, AEP issued 16.1 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $805 million. Net proceeds from the issuance were approximately $785 million. Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP’s 3.40% Junior Subordinated Notes due in 2024 and a forward equity purchase contract which settles after three years in 2022. The proceeds from this issuance were used to support AEP’s overall capital expenditure plans including the recent acquisition of Sempra Renewables LLC. See Note 13 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.70 per share in October 2019. 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 will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See “Dividend Restrictions” section of Note 13 for additional information.

Credit Ratings

AEP and its utility subsidiaries do 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 its 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. 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.

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 444.1	$ 412.6
Net Cash Flows from Operating Activities	3,349.9	3,932.6
Net Cash Flows Used for Investing Activities	(5,357.6)	(4,688.7)
Net Cash Flows from Financing Activities	2,053.4	1,281.0
Net Increase in Cash, Cash Equivalents and Restricted Cash	45.7	524.9
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 489.8	$ 937.5

Operating Activities

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in millions)	
Net Income	$ 1,767.1	$ 1,566.5
Non-Cash Adjustments to Net Income (a)	1,838.8	1,728.7
Mark-to-Market of Risk Management Contracts	(41.6)	(95.4)
Property Taxes	341.7	304.8
Deferred Fuel Over/Under-Recovery, Net	93.7	210.6
Recovery of Ohio Capacity Costs	34.1	52.7
Refund of Global Settlement	(12.4)	(5.5)
Change in Other Noncurrent Assets	(9.6)	161.6
Change in Other Noncurrent Liabilities	(16.3)	141.9
Change in Certain Components of Working Capital	(645.6)	(133.3)
Net Cash Flows from Operating Activities	$ 3,349.9	$ 3,932.6

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Deferred Income Taxes, AFUDC and Amortization of Nuclear Fuel.

Net Cash Flows from Operating Activities decreased by $583 million primarily due to the following:

- A $512 million decrease in cash from Change in Certain Components of Working Capital. The decrease is primarily due to increase in purchases of fuel, material and supplies, decreased accrued taxes, higher employee-related payments and refund related to Tax Reform, partially offset by receivables due to the changes in timing.
- A $171 million decrease in cash from Change in Other Noncurrent Assets primarily due to a change in regulatory assets as a result of AEP subsidiaries with rider recovery mechanisms. See Note 4 - Rate Matters for additional information.
- A $158 million decrease in cash from Change in Other Noncurrent Liabilities primarily due to decreased Accumulated Provisions for Rate Refunds as a result of Tax Reform
- A $117 million decrease in cash from Deferred Fuel Over/Under Recovery, Net primarily due to fluctuations APCo and WPCo as a result of the 2018 West Virginia Tax Reform Order, the full recovery of Ohio Phase in recovery rider and the fluctuations of fuel and purchase power cost at PSO.

These decreases in cash were partially offset by:

- A $310 million increase in cash from Income from Continuing Operations, after non-cash adjustments. See Results of Operations for further detail.

Investing Activities

	Nine Months Ended September 30,	
	2019	2018
	(in millions)	
Construction Expenditures	$ (4,336.0)	$ (4,688.4)
Acquisitions of Nuclear Fuel	(91.9)	(26.1)
Acquisition of Sempra Renewables LLC and Santa Rita East, net of cash and restricted cash acquired	(921.3)	—
Other	(8.4)	25.8
Net Cash Flows Used for Investing Activities	$ (5,357.6)	$ (4,688.7)

Net Cash Flows Used for Investing Activities increased by $669 million primarily due to the following:

- A $921 million increase due to the acquisition of Sempra Renewables LLC and Santa Rita East. The $921 million represents a cash payment of $939 million, net of cash and restricted cash acquired of $18 million. See Note 6 - Acquisitions and Impairments for additional information.

This increase in the use of cash was partially offset by:

- A $352 million decrease due to decreased construction expenditures, primarily driven by decreases at AEP Transmission Holdco of $210 million and Transmission and Distribution Utilities of $109 million.

Financing Activities

	Nine Months Ended September 30,	
	2019	2018
	(in millions)	
Issuance of Common Stock	$ 44.7	$ 62.5
Issuance/Retirement of Debt, Net	3,063.9	2,206.2
Dividends Paid on Common Stock	(1,002.0)	(922.5)
Other	(53.2)	(65.2)
Net Cash Flows from Financing Activities	$ 2,053.4	$ 1,281.0

Net Cash Flows from Financing Activities increased by $772 million primarily due to the following:

- A $936 million increase in cash due to decreased retirements of long-term debt. See Note 13 - Financing Activities for additional information.

This increase in cash was partially offset by:

- An $80 million decrease in issuances of long-term debt. See Note 13 - Financing Activities for additional information.
- An $80 million decrease in cash due to the increased common stock dividends payments primarily due to increase dividends per share from 2018 to 2019.

See "Long-term Debt Subsequent Events" section of Note 13 for Long-term debt and other securities issued, retired and principal payments made after September 30, 2019 through October 24, 2019, the date that the third quarter 10-Q was issued.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $32.9 billion of capital expenditures for 2019 to 2023. Capital expenditures related to North Central Wind Energy Facilities are excluded from these budgeted amounts. The expenditures are generally for transmission, generation, distribution, regulated and contracted renewables, and required environmental investment to comply with the Federal EPA rules. Estimated capital 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 capital 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. For complete information of forecasted capital expenditures, see the "Budgeted Capital Expenditures" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2018 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2018 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the "Cash Flow" section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the "Critical Accounting Policies and Estimates" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2018 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting standards.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards adopted in 2019 and standards effective in the future.

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. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates.

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

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates. In addition, the Generation & Marketing segment is also exposed to certain market risks as a power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations, Senior Vice President of Treasury and Risk and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer, Senior Vice President of Treasury and Risk 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, 2018:

MTM Risk Management Contract Net Assets (Liabilities)

Nine Months Ended September 30, 2019

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2018	$ 90.9	$ (101.0)	$ 164.5	$ 154.4
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(65.5)	(5.0)	(14.3)	(84.8)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	8.8	8.8
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	12.8	12.8
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	76.9	(7.2)	—	69.7
Total MTM Risk Management Contract Net Assets (Liabilities) as of September 30, 2019	$ 102.3	$ (113.2)	$ 171.8	160.9
Commodity Cash Flow Hedge Contracts				(97.3)
Interest Rate Cash Flow Hedge Contracts				1.9
Fair Value Hedge Contracts				25.1
Collateral Deposits				21.2
Total MTM Derivative Contract Net Assets as of September 30, 2019				$ 111.8

(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 or accounts payable.

See Note 9 – Derivatives and Hedging and Note 10 – 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 credit agency ratings 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 (includes non-derivative 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 September 30, 2019, credit exposure net of collateral to sub investment grade counterparties was approximately 6.4%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss).

As of September 30, 2019, 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	$ 529.6	$ 0.3	$ 529.3	2	$ 218.3
Split Rating	0.8	—	0.8	1	0.8
No External Ratings:					
Internal Investment Grade	138.2	—	138.2	3	84.2
Internal Noninvestment Grade	56.2	10.5	45.7	2	30.1
Total as of September 30, 2019	$ 724.8	$ 10.8	$ 714.0		

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 September 30, 2019, 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

Nine Months Ended September 30, 2019				Twelve Months Ended December 31, 2018			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.3	$ 1.2	$ 0.2	$ 0.1	$ 1.1	$ 1.8	$ 0.3	$ 0.1

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2019				Twelve Months Ended December 31, 2018			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.2	$ 8.5	$ 1.3	$ 0.2	$ 4.0	$ 16.5	$ 2.7	$ 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

AEP is exposed to interest rate market fluctuations in the normal course of business operations. AEP has outstanding short and long-term debt which is subject to a variable rate. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the nine months ended September 30, 2019 and 2018, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $24 million and $25 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
REVENUES				
Vertically Integrated Utilities	$ 2,598.9	$ 2,610.2	$ 7,087.6	$ 7,332.4
Transmission and Distribution Utilities	1,147.3	1,180.9	3,328.7	3,450.0
Generation & Marketing	501.2	486.5	1,323.8	1,399.3
Other Revenues	67.6	55.5	205.3	212.9
TOTAL REVENUES	4,315.0	4,333.1	11,945.4	12,394.6
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	631.2	840.4	1,662.5	1,909.1
Purchased Electricity for Resale	783.9	784.7	2,306.4	2,551.7
Other Operation	708.3	826.0	1,981.7	2,332.7
Maintenance	267.7	316.6	890.9	911.0
Depreciation and Amortization	645.2	602.6	1,873.6	1,695.5
Taxes Other Than Income Taxes	320.5	294.2	932.7	863.0
TOTAL EXPENSES	3,356.8	3,664.5	9,647.8	10,263.0
OPERATING INCOME	958.2	668.6	2,297.6	2,131.6
Other Income (Expense):				
Other Income	3.2	6.3	18.4	18.5
Allowance for Equity Funds Used During Construction	43.0	30.9	122.3	92.4
Non-Service Cost Components of Net Periodic Benefit Cost	30.0	31.9	90.0	95.3
Interest Expense	(275.1)	(256.8)	(781.6)	(733.1)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	759.3	480.9	1,746.7	1,604.7
Income Tax Expense (Benefit)	40.6	(80.7)	30.7	93.5
Equity Earnings of Unconsolidated Subsidiaries	15.2	18.1	51.1	55.3
NET INCOME	733.9	579.7	1,767.1	1,566.5
Net Income (Loss) Attributable to Noncontrolling Interests	0.4	2.1	(0.5)	6.1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 733.5	$ 577.6	$ 1,767.6	$ 1,560.4
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	493,839,034	492,984,741	493,579,430	492,649,456
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.49	$ 1.17	$ 3.58	$ 3.17
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	495,461,509	493,940,543	495,105,986	493,526,937
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.48	$ 1.17	$ 3.57	$ 3.16

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Net Income	$ 733.9	$ 579.7	$ 1,767.1	$ 1,566.5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $11.8 and $2.7 for the Three Months Ended September 30, 2019 and 2018, Respectively, and $(16.8) and $3.9 for the Nine Months Ended September 30, 2019 and 2018, Respectively	44.2	10.2	(63.3)	14.7
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.4) and $(0.4) for the Three Months Ended September 30, 2019 and 2018, Respectively, and $(1.1) and $(1.1) for the Nine Months Ended September 30, 2019 and 2018, Respectively	(1.4)	(1.4)	(4.2)	(4.0)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	42.8	8.8	(67.5)	10.7
TOTAL COMPREHENSIVE INCOME	776.7	588.5	1,699.6	1,577.2
Total Other Comprehensive Income (Loss) Attributable To Noncontrolling Interests	0.4	2.1	(0.5)	6.1
TOTAL OTHER COMPREHENSIVE INCOME ATTIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 776.3	$ 586.4	$ 1,700.1	$ 1,571.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2017	512.2	$ 3,329.4	$ 6,398.7	$ 8,626.7	$ (67.8)	$ 26.6	$ 18,313.6
Issuance of Common Stock	0.5	3.3	28.9				32.2
Common Stock Dividends				(305.5) (b)		(0.6)	(306.1)
Other Changes in Equity			16.9				16.9
ASU 2018-02 Adoption				14.0	(17.0)		(3.0)
ASU 2016-01 Adoption				11.9	(11.9)		—
Net Income				454.4		2.3	456.7
Other Comprehensive Income					1.3		1.3
TOTAL EQUITY – MARCH 31, 2018	512.7	3,332.7	6,444.5	8,801.5	(95.4)	28.3	18,511.6
Issuance of Common Stock	0.4	2.7	16.0				18.7
Common Stock Dividends				(306.8) (b)		(1.3)	(308.1)
Other Changes in Equity			(1.9)			0.4	(1.5)
Net Income				528.4		1.7	530.1
Other Comprehensive Income					0.6		0.6
TOTAL EQUITY – JUNE 30, 2018	513.1	3,335.4	6,458.6	9,023.1	(94.8)	29.1	18,751.4
Issuance of Common Stock	0.2	1.1	10.5				11.6
Common Stock Dividends				(307.0) (b)		(1.3)	(308.3)
Other Changes in Equity			3.5			0.1	3.6
Net Income				577.6		2.1	579.7
Other Comprehensive Income					8.8		8.8
TOTAL EQUITY – SEPTEMBER 30, 2018	513.3	$ 3,336.5	$ 6,472.6	$ 9,293.7	$ (86.0)	$ 30.0	$ 19,046.8
TOTAL EQUITY – DECEMBER 31, 2018	513.5	$ 3,337.4	$ 6,486.1	$ 9,325.3	$ (120.4)	$ 31.0	$ 19,059.4
Issuance of Common Stock	0.1	1.2	13.3				14.5
Common Stock Dividends				(332.5) (c)		(1.1)	(333.6)
Other Changes in Equity			(56.6) (a)			1.0	(55.6)
Net Income				572.8		1.3	574.1
Other Comprehensive Loss					(30.3)		(30.3)
TOTAL EQUITY – MARCH 31, 2019	513.6	3,338.6	6,442.8	9,565.6	(150.7)	32.2	19,228.5
Issuance of Common Stock	0.4	2.2	15.6				17.8
Common Stock Dividends				(332.7) (c)		(1.8)	(334.5)
Other Changes in Equity			(3.1)			0.6	(2.5)
Acquisition of Sempra Renewables LLC						134.8	134.8
Net Income (Loss)				461.3		(2.2)	459.1
Other Comprehensive Loss					(80.0)		(80.0)
TOTAL EQUITY – JUNE 30, 2019	514.0	3,340.8	6,455.3	9,694.2	(230.7)	163.6	19,423.2
Issuance of Common Stock	0.1	1.1	11.3				12.4
Common Stock Dividends				(332.4) (c)		(1.5)	(333.9)
Other Changes in Equity			0.5				0.5
Acquisition of Santa Rita East						118.8	118.8

Net Income				733.5		0.4	733.9
Other Comprehensive Income					42.8		42.8
TOTAL EQUITY – SEPTEMBER 30, 2019	514.1	$ 3,341.9	$ 6,467.1	$ 10,095.3	$ (187.9)	$ 281.3	$ 19,997.7

(a) Includes $(62) million related to a forward equity purchase contract associated with the issuance of Equity Units. See “Equity Units” section of Note 13 for additional information.
(b) Common Stock dividends declared per AEP common share were $0.62.
(c) Common Stock dividends declared per AEP common share were $0.67.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 348.8	$ 234.1
Restricted Cash (September 30, 2019 and December 31, 2018 Amounts Include $141 and $210, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Santa Rita East)	141.0	210.0
Other Temporary Investments (September 30, 2019 and December 31, 2018 Amounts Include $193.4 and $152.7, Respectively, Related to EIS and Transource Energy)	198.4	159.1
Accounts Receivable:		
Customers	609.0	699.0
Accrued Unbilled Revenues	268.8	209.3
Pledged Accounts Receivable – AEP Credit	955.6	999.8
Miscellaneous	36.6	55.2
Allowance for Uncollectible Accounts	(44.9)	(36.8)
Total Accounts Receivable	1,825.1	1,926.5
Fuel	437.8	341.5
Materials and Supplies	613.5	579.6
Risk Management Assets	186.7	162.8
Regulatory Asset for Under-Recovered Fuel Costs	98.5	150.1
Margin Deposits	54.2	141.4
Prepayments and Other Current Assets	262.4	208.8
TOTAL CURRENT ASSETS	4,166.4	4,113.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	22,624.4	21,699.9
Transmission	23,082.8	21,531.0
Distribution	21,991.0	21,195.4
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	4,510.2	4,265.0
Construction Work in Progress	5,244.5	4,393.9
Total Property, Plant and Equipment	77,452.9	73,085.2
Accumulated Depreciation and Amortization	18,760.2	17,986.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	58,692.7	55,099.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,131.4	3,310.4
Securitized Assets	938.7	920.6
Spent Nuclear Fuel and Decommissioning Trusts	2,835.2	2,474.9
Goodwill	52.5	52.5
Long-term Risk Management Assets	299.0	254.0
Operating Lease Assets	990.0	—
Deferred Charges and Other Noncurrent Assets	2,794.8	2,577.4
TOTAL OTHER NONCURRENT ASSETS	11,041.6	9,589.8
TOTAL ASSETS	$ 73,900.7	$ 68,802.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2019 and December 31, 2018
(in millions, except per-share and share amounts)
(Unaudited)

			September 30, 2019		**December 31, 2018**
CURRENT LIABILITIES					
Accounts Payable		$	1,766.8	$	1,874.3
Short-term Debt:					
Securitized Debt for Receivables – AEP Credit			750.0		750.0
Other Short-term Debt			1,760.0		1,160.0
Total Short-term Debt			2,510.0		1,910.0
Long-term Debt Due Within One Year (September 30, 2019 and December 31, 2018 Amounts Include $544.7 and $406.5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)			1,327.7		1,698.5
Risk Management Liabilities			75.3		55.0
Customer Deposits			381.4		412.2
Accrued Taxes			883.4		1,218.0
Accrued Interest			304.8		231.7
Obligations Under Operating Leases			228.8		—
Regulatory Liability for Over-Recovered Fuel Costs			100.6		58.6
Other Current Liabilities			1,032.4		1,190.5
TOTAL CURRENT LIABILITIES			8,611.2		8,648.8
NONCURRENT LIABILITIES					
Long-term Debt (September 30, 2019 and December 31, 2018 Amounts Include $918.4 and $1,109.2, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)			24,553.5		21,648.2
Long-term Risk Management Liabilities			298.6		263.4
Deferred Income Taxes			7,427.8		7,086.5
Regulatory Liabilities and Deferred Investment Tax Credits			8,552.8		8,540.3
Asset Retirement Obligations			2,353.5		2,287.7
Employee Benefits and Pension Obligations			376.6		377.1
Obligations Under Operating Leases			801.1		—
Deferred Credits and Other Noncurrent Liabilities			790.0		782.6
TOTAL NONCURRENT LIABILITIES			45,153.9		40,985.8
TOTAL LIABILITIES			53,765.1		49,634.6
Rate Matters (Note 4)					
Commitments and Contingencies (Note 5)					
MEZZANINE EQUITY					
Redeemable Noncontrolling Interest			67.3		69.4
Contingently Redeemable Performance Share Awards			70.6		39.4
TOTAL MEZZANINE EQUITY			137.9		108.8
EQUITY					
Common Stock – Par Value – $6.50 Per Share:					
	2019	**2018**			
Shares Authorized	600,000,000	600,000,000			
Shares Issued	514,140,235	513,450,036			
(20,204,160 Shares were Held in Treasury as of September 30, 2019 and December 31, 2018, Respectively)			3,341.9		3,337.4

Paid-in Capital	6,467.1	6,486.1
Retained Earnings	10,095.3	9,325.3
Accumulated Other Comprehensive Income (Loss)	(187.9)	(120.4)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	19,716.4	19,028.4
Noncontrolling Interests	281.3	31.0
TOTAL EQUITY	19,997.7	19,059.4
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY	$ 73,900.7	$ 68,802.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2019	**2018**
OPERATING ACTIVITIES		
Net Income	$ 1,767.1	$ 1,566.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,873.6	1,695.5
Deferred Income Taxes	15.9	43.0
Allowance for Equity Funds Used During Construction	(122.3)	(92.4)
Mark-to-Market of Risk Management Contracts	(41.6)	(95.4)
Amortization of Nuclear Fuel	71.6	82.6
Property Taxes	341.7	304.8
Deferred Fuel Over/Under-Recovery, Net	93.7	210.6
Recovery of Ohio Capacity Costs	34.1	52.7
Refund of Global Settlement	(12.4)	(5.5)
Change in Other Noncurrent Assets	(9.6)	161.6
Change in Other Noncurrent Liabilities	(16.3)	141.9
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	125.0	(52.3)
Fuel, Materials and Supplies	(116.6)	98.7
Accounts Payable	(32.4)	(45.0)
Accrued Taxes, Net	(359.9)	(247.5)
Other Current Assets	60.2	11.7
Other Current Liabilities	(321.9)	101.1
Net Cash Flows from Operating Activities	3,349.9	3,932.6
INVESTING ACTIVITIES		
Construction Expenditures	(4,336.0)	(4,688.4)
Purchases of Investment Securities	(951.5)	(1,591.2)
Sales of Investment Securities	874.2	1,550.9
Acquisitions of Nuclear Fuel	(91.9)	(26.1)
Acquisition of Sempra Renewables LLC and Santa Rita East, net of cash and restricted cash acquired	(921.3)	—
Other Investing Activities	68.9	66.1
Net Cash Flows Used for Investing Activities	(5,357.6)	(4,688.7)
FINANCING ACTIVITIES		
Issuance of Common Stock	44.7	62.5
Issuance of Long-term Debt	3,492.4	3,572.0
Commercial Paper and Credit Facility Borrowings	—	205.6
Change in Short-term Debt, Net	600.0	604.0
Retirement of Long-term Debt	(1,023.5)	(1,959.5)
Make Whole Premium on Extinguishment of Long-term Debt	(5.0)	(10.3)
Commercial Paper and Credit Facility Repayments	—	(205.6)
Principal Payments for Finance Lease Obligations	(44.5)	(49.4)
Dividends Paid on Common Stock	(1,002.0)	(922.5)
Other Financing Activities	(8.7)	(15.8)
Net Cash Flows from Financing Activities	2,053.4	1,281.0
Net Increase in Cash, Cash Equivalents and Restricted Cash	45.7	524.9
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	444.1	412.6
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 489.8	$ 937.5

SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 689.7	$ 631.3
Net Cash Paid (Received) for Income Taxes	22.8	(27.9)
Noncash Acquisitions Under Finance Leases	66.7	43.5
Construction Expenditures Included in Current Liabilities as of September 30,	1,018.9	882.3
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	—	12.1
Noncash Contribution of Assets by Noncontrolling Interest	—	84.0
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	—	2.1
Noncontrolling Interest assumed with Sempra Renewable LLC and Santa Rita East Acquisition	253.4	—
Liabilities assumed with Sempra Renewable LLC and Santa Rita East Acquisition	32.4	—

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions of KWhs)			
Retail:				
Residential	4,148	3,893	9,580	9,679
Commercial	3,152	2,987	7,997	7,916
Industrial	2,168	2,216	6,556	6,705
Miscellaneous	197	182	512	490
Total Retail (a)	9,665	9,278	24,645	24,790

(a) 2018 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in degree days)			
Actual – Heating (a)	—	—	180	234
Normal – Heating (b)	—	—	190	194
Actual – Cooling (c)	1,587	1,424	2,679	2,612
Normal – Cooling (b)	1,368	1,367	2,425	2,413

(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 70 degree temperature base.

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Net Income
(in millions)

Third Quarter of 2018	$	57.8
Changes in Gross Margin:		
Retail Margins		12.6
Margins from Off-system Sales		16.7
Transmission Revenues		23.9
Other Revenues		4.7
Total Change in Gross Margin		57.9
Changes in Expenses and Other:		
Other Operation and Maintenance		6.7
Depreciation and Amortization		(36.9)
Taxes Other Than Income Taxes		(3.5)
Interest Income		(0.1)
Allowance for Equity Funds Used During Construction		(0.7)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		1.5
Total Change in Expenses and Other		(33.3)
Income Tax Expense (Benefit)		(5.4)
Third Quarter of 2019	$	77.0

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

- **Retail Margins** increased $13 million primarily due to the following:
  - An $8 million increase in weather-related usage primarily due to an 11% increase in cooling degree days.
  - A $4 million increase in weather-normalized margins primarily in the residential class.
- **Margins from Off-system Sales** increased $17 million due to higher affiliated PPA revenues. This increase was partially offset below in Other Operation and Maintenance expenses and in Depreciation and Amortization expenses.
- **Transmission Revenues** increased $24 million primarily due to the recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $5 million primarily due to securitization revenue related to Transition Funding. This decrease was offset below in Depreciation and Amortization expenses and in Interest Expense.

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

- **Other Operation and Maintenance** expenses decreased $7 million primarily due to the following:
  - A $4 million decrease in expenses associated with Oklaunion Power Station. This decrease was partially offset in Margins from Off-system Sales above and in Depreciation and Amortization expenses below.
  - A $3 million decrease in ERCOT transmission expenses. This decrease was partially offset in Retail Margins above.

- **Depreciation and Amortization** expenses increased $37 million primarily due to the following:
  - A $16 million increase in depreciation expense due to a change in the useful life of the Oklaunion Power Station. This increase was partially offset in Margins from Off-system Sales above and in Other Operation and Maintenance expenses above.
  - An $11 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets primarily related to advanced metering systems.
  - A $7 million increase in securitization amortizations primarily related to Transition Funding. This increase was offset in Other Revenues above and in Interest Expense below.
- **Taxes Other Than Income Taxes** increased $4 million primarily due to increased property taxes as a result of additional investments in transmission and distribution assets and higher tax rates.
- **Interest Expense** decreased $2 million primarily due to the following:
  - A $5 million decrease due to the deferral of previously recorded interest expense approved for recovery as a result of the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.
  - A $3 million decrease in expense related to Transition Funding Securitization assets. This decrease was offset above in Other Revenues and Depreciation and Amortization expenses.

  These decreases were partially offset by:
  - A $2 million increase due to higher long-term debt balances.
- **Income Tax Expense (Benefit)** increased $5 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Net Income
(in millions)

Nine Months Ended September 30, 2018	$	151.1
Changes in Gross Margin:		
Retail Margins		—
Margins from Off-system Sales		59.3
Transmission Revenues		62.3
Other Revenues		1.9
Total Change in Gross Margin		123.5
Changes in Expenses and Other:		
Other Operation and Maintenance		(49.9)
Depreciation and Amortization		(99.9)
Taxes Other Than Income Taxes		(8.0)
Interest Income		1.5
Allowance for Equity Funds Used During Construction		(6.9)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.8)
Interest Expense		16.2
Total Change in Expenses and Other		(147.8)
Income Tax Expense (Benefit)		65.2
Nine Months Ended September 30, 2019	$	192.0

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

- **Retail Margins** were unchanged primarily due to the following:
  - A $7 million decrease in revenues associated with the Transmission Cost Recovery Factor revenue rider. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $5 million decrease in weather-related usage primarily due to a 23% decrease in heating degree days, partially offset by a 3% increase in cooling degree days.

  These decreases were offset by:
  - A $12 million increase in weather-normalized margins primarily in the residential and commercial classes.
- **Margins from Off-system Sales** increased $59 million due to higher affiliated PPA revenues. This increase was partially offset below in Other Operation and Maintenance expenses and in Depreciation and Amortization expenses.
- **Transmission Revenues** increased $62 million primarily due to recovery of increased transmission investment in ERCOT.

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

- **Other Operation and Maintenance** expenses increased $50 million primarily due to the following:
  - A $64 million increase in expense due to the partial amortization of the Texas Storm Cost Securitization regulatory asset as a result of the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019. This increase was offset in Income Tax Expense (Benefit) below.

  These increases were partially offset by:
  - A $7 million decrease in distribution expenses.
  - A $7 million decrease in ERCOT transmission expenses. This decrease was partially offset in Retail Margins above.
  - A $5 million decrease in expenses associated with Oklaunion Power Station. This decrease was partially offset in Margins from Off-system Sales above and in Depreciation and Amortization expenses below.

- **Depreciation and Amortization** expenses increased $100 million primarily due to the following:
  - A $49 million increase in depreciation expense due to a change in the useful life of the Oklaunion Power Station. This increase was offset above in Margins from Off-system Sales and in Other Operation and Maintenance expenses.
  - A $34 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets primarily related to advanced metering systems.
  - A $9 million increase in securitization amortizations primarily related to Transition Funding. This increase was offset in Other Revenues above and in Interest Expense below.
  - A $6 million increase in ARO associated with Oklaunion Power Station.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Allowance for Equity Funds Used During Construction** decreased $7 million primarily due to a decrease in the Equity component as a result of higher short-term debt balances, partially offset by increased transmission projects.
- **Interest Expense** decreased $16 million primarily due to:
  - A $21 million decrease due to the deferral of previously recorded interest expense approved for recovery as a result of the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.
  - An $8 million decrease in expense related to Transition Funding Securitization assets. This decrease was offset above in Other Revenues and Depreciation and Amortization expenses.

  These decreases were partially offset by:
  - An $11 million increase due to higher long-term debt balances.
- **Income Tax Expense (Benefit)** decreased $65 million primarily due to the amortization of Excess ADIT not subject to normalization requirements as approved in the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019. This decrease was partially offset above in Other Operation and Maintenance expenses.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
REVENUES				
Electric Transmission and Distribution	$ 445.4	$ 404.5	$ 1,190.3	$ 1,127.0
Sales to AEP Affiliates	42.7	27.5	125.1	63.3
Other Revenues	1.2	1.4	2.6	3.0
TOTAL REVENUES	489.3	433.4	1,318.0	1,193.3
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	11.2	13.2	29.1	27.9
Other Operation	128.2	133.4	349.2	368.4
Maintenance	21.7	23.2	136.9	67.8
Depreciation and Amortization	170.2	133.3	464.8	364.9
Taxes Other Than Income Taxes	39.8	36.3	110.3	102.3
TOTAL EXPENSES	371.1	339.4	1,090.3	931.3
OPERATING INCOME	118.2	94.0	227.7	262.0
Other Income (Expense):				
Interest Income	0.4	0.5	1.5	—
Allowance for Equity Funds Used During Construction	5.1	5.8	8.3	15.2
Non-Service Cost Components of Net Periodic Benefit Cost	2.8	3.1	8.4	9.2
Interest Expense	(35.8)	(37.3)	(92.7)	(108.9)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	90.7	66.1	153.2	177.5
Income Tax Expense (Benefit)	13.7	8.3	(38.8)	26.4
NET INCOME	$ 77.0	$ 57.8	$ 192.0	$ 151.1

The common stock of AEP Texas is wholly-owned by Parent.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Net Income	$ 77.0	$ 57.8	$ 192.0	$ 151.1
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2019 and 2018, Respectively, and $0.2 and $0.2 for the Nine Months Ended September 30, 2019 and 2018, Respectively	0.3	0.3	0.8	0.8
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2019 and 2018, Respectively, and $0 and $0 for the Nine Months Ended September 30, 2019 and 2018, Respectively	—	—	0.1	0.1
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.3	0.9	0.9
TOTAL COMPREHENSIVE INCOME	$ 77.3	$ 58.1	$ 192.9	$ 152.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 1,057.9	$ 1,124.6	$ (12.6)	$ 2,169.9
Capital Contribution from Parent	100.0			100.0
ASU 2018-02 Adoption		1.8	(2.7)	(0.9)
Net Income		46.8		46.8
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	1,157.9	1,173.2	(15.0)	2,316.1
Net Income		46.5		46.5
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	1,157.9	1,219.7	(14.7)	2,362.9
Net Income		57.8		57.8
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 1,157.9	$ 1,277.5	$ (14.4)	$ 2,421.0
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 1,257.9	$ 1,337.7	$ (15.1)	$ 2,580.5
Capital Contribution from Parent	200.0			200.0
Net Income		34.4		34.4
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	1,457.9	1,372.1	(14.8)	2,815.2
Net Income		80.6		80.6
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	1,457.9	1,452.7	(14.5)	2,896.1
Net Income		77.0		77.0
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2019	$ 1,457.9	$ 1,529.7	$ (14.2)	$ 2,973.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 0.1	$ 3.1
Restricted Cash for Securitized Transition Funding	114.3	156.7
Advances to Affiliates	7.7	8.0
Accounts Receivable:		
Customers	148.0	110.9
Affiliated Companies	17.6	15.0
Accrued Unbilled Revenues	82.7	70.4
Miscellaneous	0.2	1.9
Allowance for Uncollectible Accounts	(1.6)	(1.3)
Total Accounts Receivable	246.9	196.9
Fuel	7.1	8.8
Materials and Supplies	54.6	52.8
Accrued Tax Benefits	111.3	44.9
Prepayments and Other Current Assets	6.4	5.3
TOTAL CURRENT ASSETS	548.4	476.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	351.8	352.1
Transmission	4,102.8	3,683.6
Distribution	4,122.2	4,043.2
Other Property, Plant and Equipment	775.3	727.9
Construction Work in Progress	978.4	836.2
Total Property, Plant and Equipment	10,330.5	9,643.0
Accumulated Depreciation and Amortization	1,742.7	1,651.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,587.8	7,991.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	259.6	430.0
Securitized Assets (September 30, 2019 and December 31, 2018 Amounts Include $693 and $636.8, Respectively, Related to Transition Funding and Restoration Funding)	698.1	649.1
Deferred Charges and Other Noncurrent Assets	161.9	56.3
TOTAL OTHER NONCURRENT ASSETS	1,119.6	1,135.4
TOTAL ASSETS	$ 10,255.8	$ 9,603.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT LIABILITIES		
Advances from Affiliates	$ 74.8	$ 216.0
Accounts Payable:		
General	224.1	276.5
Affiliated Companies	41.0	30.3
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2019 and December 31, 2018 Amounts Include $280.8 and $251.1, Respectively, Related to Transition Funding and Restoration Funding)	391.4	501.1
Risk Management Liabilities	0.3	0.2
Accrued Taxes	108.5	75.5
Accrued Interest (September 30, 2019 and December 31, 2018 Amounts Include $6.1 and $11.3, Respectively, Related to Transition Funding and Restoration Funding)	50.6	37.3
Oklaunion Purchase Power Agreement	28.7	24.3
Obligations Under Operating Leases	11.7	—
Other Current Liabilities	85.1	98.3
TOTAL CURRENT LIABILITIES	1,016.2	1,259.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2019 and December 31, 2018 Amounts Include $530.5 and $540.1, Respectively, Related to Transition Funding and Restoration Funding)	3,755.1	3,380.2
Long-term Risk Management Liabilities	0.1	—
Deferred Income Taxes	977.7	913.1
Regulatory Liabilities and Deferred Investment Tax Credits	1,325.1	1,344.3
Oklaunion Purchase Power Agreement	—	22.1
Obligations Under Operating Leases	71.1	—
Deferred Credits and Other Noncurrent Liabilities	137.1	104.0
TOTAL NONCURRENT LIABILITIES	6,266.2	5,763.7
TOTAL LIABILITIES	7,282.4	7,023.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	1,457.9	1,257.9
Retained Earnings	1,529.7	1,337.7
Accumulated Other Comprehensive Income (Loss)	(14.2)	(15.1)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,973.4	2,580.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,255.8	$ 9,603.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2019	2018
OPERATING ACTIVITIES		
Net Income	$ 192.0	$ 151.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	464.8	364.9
Deferred Income Taxes	(0.6)	(21.2)
Allowance for Equity Funds Used During Construction	(8.3)	(15.2)
Mark-to-Market of Risk Management Contracts	0.2	—
Change in Other Noncurrent Assets	0.5	(55.7)
Change in Other Noncurrent Liabilities	6.5	67.1
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(50.0)	(26.5)
Fuel, Materials and Supplies	(0.1)	(2.4)
Accounts Payable	17.8	(19.1)
Accrued Taxes, Net	(33.4)	40.0
Other Current Assets	(0.7)	(6.3)
Other Current Liabilities	(12.9)	14.1
Net Cash Flows from Operating Activities	575.8	490.8
INVESTING ACTIVITIES		
Construction Expenditures	(954.5)	(1,096.1)
Change in Advances to Affiliates, Net	0.3	103.9
Other Investing Activities	18.4	31.1
Net Cash Flows Used for Investing Activities	(935.8)	(961.1)
FINANCING ACTIVITIES		
Capital Contribution from Parent	200.0	100.0
Issuance of Long-term Debt – Nonaffiliated	627.5	494.0
Change in Advances from Affiliates, Net	(141.2)	77.8
Retirement of Long-term Debt – Nonaffiliated	(366.8)	(231.7)
Principal Payments for Finance Lease Obligations	(3.8)	(3.6)
Other Financing Activities	(1.1)	0.9
Net Cash Flows from Financing Activities	314.6	437.4
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding	(45.4)	(32.9)
Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding at Beginning of Period	159.8	157.2
Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding at End of Period	$ 114.4	$ 124.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 95.1	$ 92.2
Net Cash Paid (Received) for Income Taxes	28.7	(14.2)
Noncash Acquisitions Under Finance Leases	6.9	8.9
Construction Expenditures Included in Current Liabilities as of September 30,	183.6	176.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of September 30,	
	2019	2018
	(in millions)	
Plant In Service	$ 7,409.0	$ 5,988.7
Construction Work in Progress	1,858.4	1,772.9
Accumulated Depreciation and Amortization	368.8	234.6
Total Transmission Property, Net	$ 8,898.6	$ 7,527.0

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Net Income
(in millions)

Third Quarter of 2018	$ 78.1
Changes in Transmission Revenues:	
Transmission Revenues	65.3
Total Change in Transmission Revenues	65.3
Changes in Expenses and Other:	
Other Operation and Maintenance	(1.9)
Depreciation and Amortization	(10.4)
Taxes Other Than Income Taxes	(7.7)
Interest Income	0.3
Allowance for Equity Funds Used During Construction	3.0
Interest Expense	(6.6)
Total Change in Expenses and Other	(23.3)
Income Tax Expense	(12.5)
Third Quarter of 2019	$ 107.6

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

- **Transmission Revenues** increased $65 million primarily due to continued investment in transmission assets.

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

- **Depreciation and Amortization** expenses increased $10 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $3 million primarily due to higher CWIP balances.
- **Interest Expense** increased $7 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $13 million primarily due to higher pretax book income.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Net Income
(in millions)

Nine Months Ended September 30, 2018	$	244.2
Changes in Transmission Revenues:		
Transmission Revenues		183.9
Total Change in Transmission Revenues		183.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(3.4)
Depreciation and Amortization		(30.9)
Taxes Other Than Income Taxes		(23.3)
Interest Income		0.8
Allowance for Equity Funds Used During Construction		12.4
Interest Expense		(8.8)
Total Change in Expenses and Other		(53.2)
Income Tax Expense		(27.0)
Nine Months Ended September 30, 2019	$	347.9

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

- **Transmission Revenues** increased $184 million primarily due to continued investment in transmission assets.

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

- **Depreciation and Amortization** expenses increased $31 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $23 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $12 million primarily due to the following:
  - A $13 million increase primarily due to higher CWIP balances.
  - A $12 million increase due to the FERC's approval of a settlement agreement.

  These increases were partially offset by:
  - A $13 million decrease due to recent FERC audit findings.
- **Interest Expense** increased $9 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $27 million primarily due to higher pretax book income.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
REVENUES				
Transmission Revenues	$ 54.0	$ 46.0	$ 162.1	$ 132.3
Sales to AEP Affiliates	205.7	148.4	608.0	453.8
Other Revenues	—	—	—	0.1
TOTAL REVENUES	259.7	194.4	770.1	586.2
EXPENSES				
Other Operation	26.0	24.5	61.7	59.6
Maintenance	3.2	2.8	8.9	7.6
Depreciation and Amortization	45.3	34.9	128.4	97.5
Taxes Other Than Income Taxes	42.9	35.2	126.2	102.9
TOTAL EXPENSES	117.4	97.4	325.2	267.6
OPERATING INCOME	142.3	97.0	444.9	318.6
Other Income (Expense):				
Interest Income	0.8	0.5	2.1	1.3
Allowance for Equity Funds Used During Construction	21.0	18.0	61.1	48.7
Interest Expense	(26.4)	(19.8)	(69.5)	(60.7)
INCOME BEFORE INCOME TAX EXPENSE	137.7	95.7	438.6	307.9
Income Tax Expense	30.1	17.6	90.7	63.7
NET INCOME	$ 107.6	$ 78.1	$ 347.9	$ 244.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2017	$ 1,816.6	$ 773.3	$ 2,589.9
Capital Contribution from Member	65.0		65.0
Net Income		84.1	84.1
TOTAL MEMBER'S EQUITY – MARCH 31, 2018	1,881.6	857.4	2,739.0
Capital Contributions from Member	312.0		312.0
Net Income		82.0	82.0
TOTAL MEMBER'S EQUITY – JUNE 30, 2018	2,193.6	939.4	3,133.0
Capital Contribution from Member	205.0		205.0
Net Income		78.1	78.1
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2018	$ 2,398.6	$ 1,017.5	$ 3,416.1
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2018	$ 2,480.6	$ 1,089.2	$ 3,569.8
Net Income		104.3	104.3
TOTAL MEMBER'S EQUITY – MARCH 31, 2019	2,480.6	1,193.5	3,674.1
Net Income		136.0	136.0
TOTAL MEMBER'S EQUITY – JUNE 30, 2019	2,480.6	1,329.5	3,810.1
Net Income		107.6	107.6
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2019	$ 2,480.6	$ 1,437.1	$ 3,917.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Advances to Affiliates	$ 275.2	$ 96.9
Accounts Receivable:		
Customers	23.5	11.8
Affiliated Companies	61.3	61.0
Total Accounts Receivable	84.8	72.8
Materials and Supplies	15.1	19.0
Accrued Tax Benefits	9.7	33.4
Prepayments and Other Current Assets	4.4	3.4
TOTAL CURRENT ASSETS	389.2	225.5
TRANSMISSION PROPERTY		
Transmission Property	7,181.8	6,515.8
Other Property, Plant and Equipment	227.2	174.0
Construction Work in Progress	1,858.4	1,578.3
Total Transmission Property	9,267.4	8,268.1
Accumulated Depreciation and Amortization	368.8	271.9
TOTAL TRANSMISSION PROPERTY – NET	8,898.6	7,996.2
OTHER NONCURRENT ASSETS		
Accounts Receivable – Affiliated Companies	4.8	—
Regulatory Assets	7.3	12.9
Deferred Property Taxes	47.2	157.9
Deferred Charges and Other Noncurrent Assets	5.6	1.6
TOTAL OTHER NONCURRENT ASSETS	64.9	172.4
TOTAL ASSETS	$ 9,352.7	$ 8,394.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT LIABILITIES		
Advances from Affiliates	$ 9.1	$ 45.4
Accounts Payable:		
General	319.1	347.2
Affiliated Companies	57.1	56.0
Long-term Debt Due Within One Year – Nonaffiliated	85.0	85.0
Accrued Taxes	172.4	288.9
Accrued Interest	39.7	15.9
Obligations Under Operating Leases	2.3	—
Other Current Liabilities	25.5	3.8
TOTAL CURRENT LIABILITIES	710.2	842.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,426.9	2,738.0
Deferred Income Taxes	751.4	704.4
Regulatory Liabilities	541.2	521.3
Obligations Under Operating Leases	2.2	—
Deferred Credits and Other Noncurrent Liabilities	3.1	18.4
TOTAL NONCURRENT LIABILITIES	4,724.8	3,982.1
TOTAL LIABILITIES	5,435.0	4,824.3
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	2,480.6	2,480.6
Retained Earnings	1,437.1	1,089.2
TOTAL MEMBER'S EQUITY	3,917.7	3,569.8
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 9,352.7	$ 8,394.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2019	2018
OPERATING ACTIVITIES		
Net Income	$ 347.9	$ 244.2
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	128.4	97.5
Deferred Income Taxes	36.7	76.3
Allowance for Equity Funds Used During Construction	(61.1)	(48.7)
Property Taxes	110.7	86.9
Long-term Accounts Receivable – Affiliated	(4.8)	(3.1)
Change in Other Noncurrent Assets	5.8	12.7
Change in Other Noncurrent Liabilities	(3.8)	18.0
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(5.1)	23.5
Materials and Supplies	3.9	(2.8)
Accounts Payable	4.1	3.3
Accrued Taxes, Net	(92.8)	(73.2)
Accrued Interest	23.8	20.9
Other Current Assets	(1.0)	(0.5)
Other Current Liabilities	(8.5)	(28.0)
Net Cash Flows from Operating Activities	484.2	427.0
INVESTING ACTIVITIES		
Construction Expenditures	(959.9)	(1,171.8)
Change in Advances to Affiliates, Net	(178.3)	(131.7)
Acquisitions of Assets	(7.6)	(13.2)
Other Investing Activities	12.0	1.2
Net Cash Flows Used for Investing Activities	(1,133.8)	(1,315.5)
FINANCING ACTIVITIES		
Capital Contributions from Member	—	582.0
Issuance of Long-term Debt – Nonaffiliated	685.9	321.1
Change in Advances from Affiliates, Net	(36.3)	(14.6)
Net Cash Flows from Financing Activities	649.6	888.5
Net Change in Cash and Cash Equivalents	—	—
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 43.0	$ 38.4
Net Cash Paid (Received) for Income Taxes	29.8	(32.1)
Construction Expenditures Included in Current Liabilities as of September 30,	315.1	237.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions of KWhs)			
Retail:				
Residential	2,728	2,662	8,401	8,895
Commercial	1,721	1,715	4,812	4,980
Industrial	2,487	2,433	7,180	7,181
Miscellaneous	216	215	640	644
Total Retail (a)	7,152	7,025	21,033	21,700
Wholesale	938	1,143	2,667	2,252
Total KWhs	8,090	8,168	23,700	23,952

(a) 2018 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in degree days)			
Actual – Heating (a)	—	—	1,295	1,518
Normal – Heating (b)	3	2	1,407	1,410
Actual – Cooling (c)	1,071	950	1,530	1,495
Normal – Cooling (b)	815	814	1,194	1,184

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

__Third Quarter of 2019 Compared to Third Quarter of 2018__

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Net Income
(in millions)

Third Quarter of 2018	$	87.1
Changes in Gross Margin:		
Retail Margins		68.2
Transmission Revenues		12.8
Other Revenues		0.7
Total Change in Gross Margin		81.7
Changes in Expenses and Other:		
Other Operation and Maintenance		27.2
Depreciation and Amortization		(13.0)
Taxes Other Than Income Taxes		(3.1)
Interest Income		(0.1)
Carrying Costs Income		(0.2)
Allowance for Equity Funds Used During Construction		0.7
Non-Service Cost Components of Net Periodic Benefit Cost		(0.2)
Interest Expense		(0.8)
Total Change in Expenses and Other		10.5
Income Tax Expense (Benefit)		(75.0)
Third Quarter of 2019	$	104.3

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 $68 million primarily due to the following:
  - A $78 million increase due to a 2018 reduction in the deferred fuel under recovery balance as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - A $15 million increase in deferred fuel related to recoverable PJM expenses that were offset below.
  - An $11 million increase in weather-related usage primarily driven by a 13% increase in cooling degree days.
  - A $10 million increase due to 2018 Virginia legislation which increased non-recoverable fuel expense in the prior year.
  - An $8 million increase due to revenue primarily from rate riders in West Virginia. This increase was offset in other expense items below.
  - A $6 million increase due to a base rate increase in West Virginia implemented in March 2019.

These increases were partially offset by:
  - A $56 million decrease due to customer refunds related to Tax Reform. This decrease was partially offset in Income Tax Expense (Benefit) below.
  - A $3 million decrease in weather-normalized margins occurring across all retail classes.
- **Transmission Revenues** increased $13 million primarily due to 2018 provisions for refunds.

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

- **Other Operation and Maintenance** expenses decreased $27 million primarily due to the following:
  - A $39 million decrease due to the extinguishment of certain regulatory asset balances as agreed to within the 2018 West Virginia Tax Reform settlement.
  - A $4 million decrease in maintenance expense at various generation plants.

  These decreases were partially offset by:
  - An $11 million increase in recoverable PJM transmission expenses which were partially offset within Gross Margins above.
  - A $9 million increase in PJM expenses related to the annual formula rate true-up.
- **Depreciation and Amortization** expenses increased $13 million primarily due to a higher depreciable base and an increase in West Virginia depreciation rates beginning in March 2019.
- **Taxes Other Than Income Taxes** increased $3 million primarily due to an increase in West Virginia business and occupational taxes.
- **Income Tax Expense (Benefit)** increased $75 million primarily due to a one-time recognition of increased amortization of Excess ADIT not subject to normalization requirements as a result of the 2018 West Virginia Tax Reform settlement. This increase was partially offset in Gross Margin and Other Operation and Maintenance expenses above.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Net Income
(in millions)

Nine Months Ended September 30, 2018	$	290.0
Changes in Gross Margin:		
Retail Margins		(11.0)
Margins from Off-system Sales		2.0
Transmission Revenues		25.9
Other Revenues		1.1
Total Change in Gross Margin		18.0
Changes in Expenses and Other:		
Other Operation and Maintenance		14.4
Depreciation and Amortization		(28.8)
Taxes Other Than Income Taxes		(7.4)
Interest Income		0.8
Carrying Costs Income		(1.2)
Allowance for Equity Funds Used During Construction		2.9
Non-Service Cost Components of Net Periodic Benefit Cost		(0.6)
Interest Expense		(6.5)
Total Change in Expenses and Other		(26.4)
Income Tax Expense (Benefit)		11.9
Nine Months Ended September 30, 2019	$	293.5

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** decreased $11 million primarily due to the following:
  - A $91 million decrease due to customer refunds related to Tax Reform. This decrease was partially offset in Income Tax Expense (Benefit) below.
  - A $23 million decrease in weather-normalized margins occurring across all retail classes.
  - A $22 million decrease in weather-related usage primarily driven by a 15% decrease in heating degree days partially offset by a 2% increase in cooling degree days.

These decreases were partially offset by:
  - A $78 million increase due to a 2018 reduction in the deferred fuel under recovery balance as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - A $14 million increase primarily due to revenue from rate riders in West Virginia. This increase was offset in other expense items below.
  - A $12 million increase due to base rate increases in West Virginia implemented in March 2019.
  - A $12 million increase in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $10 million increase due to 2018 Virginia legislation which increased non-recoverable fuel expense at APCo in the prior year.
- **Transmission Revenues** increased $26 million primarily due to 2018 provisions for refunds.

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

- **Other Operation and Maintenance** expenses decreased $14 million primarily due to the following:
  - A $39 million decrease due to the extinguishment of certain regulatory asset balances as agreed to within the 2018 West Virginia Tax Reform settlement.
  - A $10 million decrease in expense due to lower current year amortization of certain regulatory assets that were extinguished in August 2018 as agreed to within the 2018 West Virginia Tax Reform settlement.
  - An $8 million decrease in maintenance expense at various generation plants.
  - A $5 million decrease in vegetation management expenses.
  - A $5 million decrease in storm-related expenses.
  - A $5 million decrease in estimated expenses for claims related to asbestos exposure.

  These decreases were partially offset by:
  - A $42 million increase in PJM expenses primarily related to the annual formula rate true-up.
  - A $13 million increase due to 2019 contributions to benefit low income West Virginia residential customers as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - A $5 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $29 million primarily due to a higher depreciable base and an increase in West Virginia depreciation rates beginning in March 2019.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to an increase in West Virginia business and occupational taxes.
- **Interest Expense** increased $7 million primarily due to higher long-term debt balances.
- **Income Tax Expense (Benefit)** decreased $12 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements and a decrease in pretax book income. This benefit was partially offset by the one-time recognition of increased amortization of Excess ADIT not subject to normalization requirements as a result of the 2018 West Virginia Tax Reform settlement. This decrease was partially offset in Gross Margin and Other Operation and Maintenance expenses above.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
REVENUES				
Electric Generation, Transmission and Distribution	$ 696.7	$ 716.8	$ 2,041.3	$ 2,103.1
Sales to AEP Affiliates	56.6	42.9	154.6	138.7
Other Revenues	2.2	2.3	8.2	7.6
TOTAL REVENUES	755.5	762.0	2,204.1	2,249.4
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	177.3	263.4	521.8	487.7
Purchased Electricity for Resale	78.3	80.4	253.4	350.8
Other Operation	140.4	131.9	416.2	380.0
Maintenance	61.5	97.2	184.3	234.9
Depreciation and Amortization	118.7	105.7	348.3	319.5
Taxes Other Than Income Taxes	36.7	33.6	108.5	101.1
TOTAL EXPENSES	612.9	712.2	1,832.5	1,874.0
OPERATING INCOME	142.6	49.8	371.6	375.4
Other Income (Expense):				
Interest Income	0.3	0.4	2.1	1.3
Carrying Costs Income	—	0.2	—	1.2
Allowance for Equity Funds Used During Construction	4.8	4.1	12.5	9.6
Non-Service Cost Components of Net Periodic Benefit Cost	4.3	4.5	12.8	13.4
Interest Expense	(51.6)	(50.8)	(152.5)	(146.0)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	100.4	8.2	246.5	254.9
Income Tax Expense (Benefit)	(3.9)	(78.9)	(47.0)	(35.1)
NET INCOME	$ 104.3	$ 87.1	$ 293.5	$ 290.0

The common stock of APCo is wholly-owned by Parent.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Net Income	$ 104.3	$ 87.1	$ 293.5	$ 290.0
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2019 and 2018, Respectively, and $(0.2) and $(0.2) for the Nine Months Ended September 30, 2019 and 2018, Respectively	(0.3)	(0.3)	(0.7)	(0.7)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.2) and $(0.2) for the Three Months Ended September 30, 2019 and 2018, Respectively, and $(0.5) and $(0.6) for the Nine Months Ended September 30, 2019 and 2018, Respectively	(0.6)	(0.7)	(1.9)	(2.3)
TOTAL OTHER COMPREHENSIVE LOSS	(0.9)	(1.0)	(2.6)	(3.0)
TOTAL COMPREHENSIVE INCOME	$ 103.4	$ 86.1	$ 290.9	$ 287.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 260.4	$ 1,828.7	$ 1,714.1	$ 1.3	$ 3,804.5
Common Stock Dividends			(40.0)		(40.0)
ASU 2018-02 Adoption			0.1	0.3	0.4
Net Income			125.5		125.5
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	260.4	1,828.7	1,799.7	0.6	3,889.4
Common Stock Dividends			(40.0)		(40.0)
Net Income			77.4		77.4
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	260.4	1,828.7	1,837.1	(0.4)	3,925.8
Common Stock Dividends			(40.0)		(40.0)
Net Income			87.1		87.1
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 260.4	$ 1,828.7	$ 1,884.2	$ (1.4)	$ 3,971.9
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 260.4	$ 1,828.7	$ 1,922.0	$ (5.0)	$ 4,006.1
Common Stock Dividends			(50.0)		(50.0)
Net Income			133.7		133.7
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	260.4	1,828.7	2,005.7	(5.8)	4,089.0
Common Stock Dividends			(50.0)		(50.0)
Net Income			55.5		55.5
Other Comprehensive Loss				(0.9)	(0.9)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	260.4	1,828.7	2,011.2	(6.7)	4,093.6
Common Stock Dividends			(25.0)		(25.0)
Net Income			104.3		104.3
Other Comprehensive Loss				(0.9)	(0.9)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2019	$ 260.4	$ 1,828.7	$ 2,090.5	$ (7.6)	$ 4,172.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.5	$ 4.2
Restricted Cash for Securitized Funding	17.1	25.6
Advances to Affiliates	22.7	23.0
Accounts Receivable:		
Customers	112.1	146.5
Affiliated Companies	56.4	73.4
Accrued Unbilled Revenues	56.9	63.5
Miscellaneous	1.0	2.3
Allowance for Uncollectible Accounts	(2.3)	(2.3)
Total Accounts Receivable	224.1	283.4
Fuel	108.8	61.3
Materials and Supplies	102.1	100.1
Risk Management Assets	56.5	57.2
Regulatory Asset for Under-Recovered Fuel Costs	43.7	99.6
Prepayments and Other Current Assets	36.3	44.3
TOTAL CURRENT ASSETS	614.8	698.7
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,560.5	6,509.6
Transmission	3,412.4	3,317.7
Distribution	4,126.7	3,989.4
Other Property, Plant and Equipment	525.3	485.8
Construction Work in Progress	667.4	490.2
Total Property, Plant and Equipment	15,292.3	14,792.7
Accumulated Depreciation and Amortization	4,300.2	4,124.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,992.1	10,668.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	474.2	475.8
Securitized Assets	240.6	258.7
Long-term Risk Management Assets	0.2	0.9
Operating Lease Assets	79.4	—
Deferred Charges and Other Noncurrent Assets	159.3	188.1
TOTAL OTHER NONCURRENT ASSETS	953.7	923.5
TOTAL ASSETS	$ 12,560.6	$ 12,290.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2019 and December 31, 2018
(Unaudited)

	September 30, 2019	December 31, 2018
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 40.4	$ 205.6
Accounts Payable:		
General	298.5	263.8
Affiliated Companies	90.8	84.0
Long-term Debt Due Within One Year – Nonaffiliated	215.6	430.7
Risk Management Liabilities	1.1	0.4
Customer Deposits	85.1	88.4
Accrued Taxes	58.2	89.3
Accrued Interest	67.5	41.5
Obligations Under Operating Leases	15.3	—
Other Current Liabilities	107.6	150.3
TOTAL CURRENT LIABILITIES	980.1	1,354.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,147.3	3,631.9
Long-term Risk Management Liabilities	0.3	0.2
Deferred Income Taxes	1,640.8	1,625.8
Regulatory Liabilities and Deferred Investment Tax Credits	1,336.9	1,449.7
Asset Retirement Obligations	108.2	107.1
Employee Benefits and Pension Obligations	52.7	57.1
Obligations Under Operating Leases	64.8	—
Deferred Credits and Other Noncurrent Liabilities	57.5	58.6
TOTAL NONCURRENT LIABILITIES	7,408.5	6,930.4
TOTAL LIABILITIES	8,388.6	8,284.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,828.7	1,828.7
Retained Earnings	2,090.5	1,922.0
Accumulated Other Comprehensive Income (Loss)	(7.6)	(5.0)
TOTAL COMMON SHAREHOLDER'S EQUITY	4,172.0	4,006.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,560.6	$ 12,290.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2019	2018
OPERATING ACTIVITIES		
Net Income	$ 293.5	$ 290.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	348.3	319.5
Deferred Income Taxes	(101.9)	(83.8)
Allowance for Equity Funds Used During Construction	(12.5)	(9.6)
Mark-to-Market of Risk Management Contracts	2.2	(43.7)
Deferred Fuel Over/Under-Recovery, Net	60.8	12.8
Change in Other Noncurrent Assets	6.7	94.8
Change in Other Noncurrent Liabilities	(29.6)	3.8
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	61.7	39.4
Fuel, Materials and Supplies	(49.2)	53.0
Accounts Payable	40.1	(21.5)
Accrued Taxes, Net	(30.2)	(20.2)
Other Current Assets	6.8	(7.9)
Other Current Liabilities	(25.1)	64.1
Net Cash Flows from Operating Activities	571.6	690.7
INVESTING ACTIVITIES		
Construction Expenditures	(607.1)	(575.8)
Change in Advances to Affiliates, Net	0.3	0.4
Other Investing Activities	22.8	10.0
Net Cash Flows Used for Investing Activities	(584.0)	(565.4)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	478.2	103.3
Change in Advances from Affiliates, Net	(165.2)	(87.5)
Retirement of Long-term Debt – Nonaffiliated	(180.4)	(24.0)
Principal Payments for Finance Lease Obligations	(5.0)	(5.2)
Dividends Paid on Common Stock	(125.0)	(120.0)
Other Financing Activities	0.6	1.0
Net Cash Flows from (Used for) Financing Activities	3.2	(132.4)
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(9.2)	(7.1)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	29.8	19.2
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 20.6	$ 12.1
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 120.6	$ 104.5
Net Cash Paid for Income Taxes	58.7	26.7
Noncash Acquisitions Under Finance Leases	7.1	3.9
Construction Expenditures Included in Current Liabilities as of September 30,	134.2	87.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions of KWhs)			
Retail:				
Residential	1,496	1,562	4,159	4,430
Commercial	1,312	1,348	3,555	3,708
Industrial	1,937	2,018	5,742	5,920
Miscellaneous	16	15	49	50
Total Retail (a)	4,761	4,943	13,505	14,108
Wholesale	2,398	2,613	6,842	7,927
Total KWhs	7,159	7,556	20,347	22,035

(a) 2018 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in degree days)			
Actual – Heating (a)	—	2	2,456	2,523
Normal – Heating (b)	11	10	2,412	2,413
Actual – Cooling (c)	684	722	917	1,084
Normal – Cooling (b)	573	574	836	837

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

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Net Income
(in millions)

Third Quarter of 2018	$	72.7
Changes in Gross Margin:		
Retail Margins		17.5
Transmission Revenues		(1.7)
Other Revenues		3.4
Total Change in Gross Margin		19.2
Changes in Expenses and Other:		
Other Operation and Maintenance		(17.1)
Depreciation and Amortization		(2.9)
Taxes Other Than Income Taxes		(2.1)
Other Income		(2.6)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.1)
Interest Expense		5.7
Total Change in Expenses and Other		(19.1)
Income Tax Expense (Benefit)		16.0
Third Quarter of 2019	$	88.8

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 $18 million primarily due to the following:
  - A $19 million increase from rate proceedings. This increase was partially offset in other expense items below.
  - An $8 million increase related to rider revenues, primarily due to the timing of the Indiana PJM/OSS rider recovery. This increase was partially offset in other expense items below.

  These increases were partially offset by:
  - A $6 million decrease in weather-normalized margins across all retail classes.
  - A $3 million decrease in weather-related usage primarily due to a 5% decrease in cooling degree days.
- **Other Revenues** increased $3 million primarily due to an increase in barging deliveries by River Transportation Division (RTD). The increase in RTD revenue was offset by a corresponding increase in Other Operation and Maintenance expenses for barging activities discussed below.

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

- **Other Operation and Maintenance** expenses increased $17 million primarily due to the following:
  - A $15 million increase in transmission expenses primarily due to a $10 million increase in recoverable PJM expenses and a $6 million increase from the amortization of credits under the 2018 Regional Transmission Enhancement Plan settlement. This increase was partially offset in Retail Margins above.
  - A $4 million increase in RTD expenses for barging activities. The increase in RTD expenses was offset by a corresponding increase in Other Revenues from barging activities discussed above.
- **Depreciation and Amortization** expenses increased $3 million primarily due to a higher depreciable base. This increase was partially offset in Retail Margins above.
- **Interest Expense** decreased $6 million primarily due to the reissuance of long-term debt at lower interest rates in 2018.
- **Income Tax Expense (Benefit)** decreased $16 million primarily due to increased amortization of Excess ADIT not subject to normalization requirements and a decrease in flow-through tax expense.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Net Income
(in millions)

Nine Months Ended September 30, 2018	$	231.6
Changes in Gross Margin:		
Retail Margins		89.7
Margins from Off-system Sales		(9.4)
Transmission Revenues		(12.0)
Other Revenues		3.7
Total Change in Gross Margin		72.0
Changes in Expenses and Other:		
Other Operation and Maintenance		(36.6)
Depreciation and Amortization		(54.5)
Taxes Other Than Income Taxes		(5.7)
Other Income		(0.1)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		9.7
Total Change in Expenses and Other		(87.5)
Income Tax Expense (Benefit)		31.9
Nine Months Ended September 30, 2019	$	248.0

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 $90 million primarily due to the following:
  - A $94 million increase from rate proceedings, inclusive of a $30 million decrease due to the impact of Tax Reform. This increase was partially offset in other expense items below.
  - A $21 million increase related to rider revenues, primarily due to the timing of the Indiana PJM/OSS rider recovery. This increase was partially offset in other expense items below.
  - A $6 million decrease in fuel-related expenses due to timing of recovery for fuel and other variable production costs related to wholesale contracts.

  These increases were partially offset by:
  - A $19 million decrease in weather-related usage primarily due to a 15% decrease in cooling degree days and a 3% decrease in heating degree days.
  - A $16 million decrease in weather-normalized margins across all retail classes.
- **Margins from Off-system Sales** decreased $9 million primarily due to mid-year 2018 changes in the OSS sharing mechanism.
- **Transmission Revenues** decreased $12 million primarily due to the 2018 PJM Transmission formula rate true-up.
- **Other Revenues** increased $4 million primarily due to an increase in barging deliveries by RTD. The increase in RTD revenue was offset by a corresponding increase in Other Operation and Maintenance expenses for barging activities discussed below.

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

Other Operation and Maintenance expenses increased $37 million primarily due to the following:

- A $32 million increase in transmission expenses primarily due to a $44 million increase in recoverable PJM expenses, partially offset by an $11 million decrease from the amortization of credits under the 2018 Regional Transmission Enhancement Plan settlement. This increase was partially offset in Retail Margins above.
- A $6 million increase in RTD expenses for barging activities. The increase in RTD expenses was offset by a corresponding increase in Other Revenues from barging activities discussed above.
- A $5 million increase in distribution costs primarily due to vegetation management expenses.

These increases were partially offset by:

- A $9 million decrease in generation expenses at Cook Plant primarily due to decreased incremental refueling outage costs.

- **Depreciation and Amortization** expenses increased $55 million primarily due to increased depreciation rates approved in 2018 and a higher depreciable base. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $6 million due to property taxes driven by an increase in utility plant.
- **Interest Expense** decreased $10 million primarily due to the reissuance of long-term debt at lower interest rates in 2018.
- **Income Tax Expense (Benefit)** decreased $32 million primarily due to increased amortization of Excess ADIT not subject to normalization requirements and a decrease in flow-through tax expense.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
REVENUES				
Electric Generation, Transmission and Distribution	$ 589.1	$ 609.9	$ 1,703.2	$ 1,723.9
Sales to AEP Affiliates	2.7	3.4	7.3	18.9
Other Revenues – Affiliated	16.2	13.7	50.4	43.3
Other Revenues – Nonaffiliated	3.1	2.7	7.6	10.1
TOTAL REVENUES	611.1	629.7	1,768.5	1,796.2
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	61.2	95.9	161.2	246.8
Purchased Electricity for Resale	44.8	48.9	163.3	167.7
Purchased Electricity from AEP Affiliates	61.0	60.0	172.1	181.8
Other Operation	172.7	149.3	467.7	425.8
Maintenance	50.9	57.2	163.8	169.1
Depreciation and Amortization	88.1	85.2	261.6	207.1
Taxes Other Than Income Taxes	25.1	23.0	78.6	72.9
TOTAL EXPENSES	503.8	519.5	1,468.3	1,471.2
OPERATING INCOME	107.3	110.2	300.2	325.0
Other Income (Expense):				
Other Income	3.5	6.1	15.3	15.4
Non-Service Cost Components of Net Periodic Benefit Cost	4.5	4.6	13.3	13.6
Interest Expense	(28.8)	(34.5)	(85.9)	(95.6)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	86.5	86.4	242.9	258.4
Income Tax Expense (Benefit)	(2.3)	13.7	(5.1)	26.8
NET INCOME	$ 88.8	$ 72.7	$ 248.0	$ 231.6

The common stock of I&M is wholly-owned by Parent.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
Net Income	$ 88.8	$ 72.7	$ 248.0	$ 231.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2019 and 2018, Respectively, and $0.3 and $0.3 for the Nine Months Ended September 30, 2019 and 2018, Respectively	0.4	0.3	1.2	1.2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2019 and 2018, Respectively, and $0 and $0 for the Nine Months Ended September 30, 2019 and 2018, Respectively	—	—	(0.1)	—
TOTAL OTHER COMPREHENSIVE INCOME	0.4	0.3	1.1	1.2
TOTAL COMPREHENSIVE INCOME	$ 89.2	$ 73.0	$ 249.1	$ 232.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 56.6	$ 980.9	$ 1,192.2	$ (12.1)	$ 2,217.6
Common Stock Dividends			(33.5)		(33.5)
ASU 2018-02 Adoption			0.3	(2.7)	(2.4)
Net Income			64.2		64.2
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	56.6	980.9	1,223.2	(14.4)	2,246.3
Common Stock Dividends			(33.5)		(33.5)
Net Income			94.7		94.7
Other Comprehensive Income				0.5	0.5
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	56.6	980.9	1,284.4	(13.9)	2,308.0
Common Stock Dividends			(38.5)		(38.5)
Net Income			72.7		72.7
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 56.6	$ 980.9	$ 1,318.6	$ (13.6)	$ 2,342.5
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 56.6	$ 980.9	$ 1,329.1	$ (13.8)	$ 2,352.8
Common Stock Dividends			(20.0)		(20.0)
Net Income			98.9		98.9
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	56.6	980.9	1,408.0	(13.4)	2,432.1
Common Stock Dividends			(20.0)		(20.0)
Net Income			60.3		60.3
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	56.6	980.9	1,448.3	(13.1)	2,472.7
Common Stock Dividends			(20.0)		(20.0)
Net Income			88.8		88.8
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2019	$ 56.6	$ 980.9	$ 1,517.1	$ (12.7)	$ 2,541.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.5	$ 2.4
Advances to Affiliates	13.2	12.7
Accounts Receivable:		
Customers	45.0	63.1
Affiliated Companies	45.3	75.0
Accrued Unbilled Revenues	2.7	3.6
Miscellaneous	1.0	1.4
Allowance for Uncollectible Accounts	(0.1)	(0.1)
Total Accounts Receivable	93.9	143.0
Fuel	39.8	37.3
Materials and Supplies	169.9	167.3
Risk Management Assets	10.5	8.6
Accrued Tax Benefits	43.2	26.6
Accrued Reimbursement of Spent Nuclear Fuel Costs	24.2	7.9
Prepayments and Other Current Assets	16.9	24.6
TOTAL CURRENT ASSETS	414.1	430.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,002.0	4,887.2
Transmission	1,614.5	1,576.8
Distribution	2,373.3	2,249.7
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	607.2	583.8
Construction Work in Progress	516.2	465.3
Total Property, Plant and Equipment	10,113.2	9,762.8
Accumulated Depreciation, Depletion and Amortization	3,280.5	3,151.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,832.7	6,611.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	490.2	512.5
Spent Nuclear Fuel and Decommissioning Trusts	2,835.2	2,474.9
Long-term Risk Management Assets	0.1	0.6
Operating Lease Assets	295.3	—
Deferred Charges and Other Noncurrent Assets	129.6	193.0
TOTAL OTHER NONCURRENT ASSETS	3,750.4	3,181.0
TOTAL ASSETS	$ 10,997.2	$ 10,222.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2019 and December 31, 2018
(dollars in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT LIABILITIES		
Advances from Affiliates	$ 102.4	$ 1.1
Accounts Payable:		
General	148.4	174.7
Affiliated Companies	71.6	70.2
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2019 and December 31, 2018 Amounts Include $68.8 and $76.8, Respectively, Related to DCC Fuel)	147.4	155.4
Risk Management Liabilities	0.2	0.3
Customer Deposits	37.9	38.0
Accrued Taxes	57.9	90.7
Accrued Interest	20.5	37.3
Obligations Under Operating Leases	82.0	—
Regulatory Liability for Over-Recovered Fuel Costs	7.3	27.4
Other Current Liabilities	85.5	103.0
TOTAL CURRENT LIABILITIES	761.1	698.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,884.1	2,880.0
Long-term Risk Management Liabilities	—	0.1
Deferred Income Taxes	970.0	948.0
Regulatory Liabilities and Deferred Investment Tax Credits	1,809.0	1,574.5
Asset Retirement Obligations	1,731.5	1,681.3
Obligations Under Operating Leases	234.0	—
Deferred Credits and Other Noncurrent Liabilities	65.6	87.8
TOTAL NONCURRENT LIABILITIES	7,694.2	7,171.7
TOTAL LIABILITIES	8,455.3	7,869.8
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	980.9	980.9
Retained Earnings	1,517.1	1,329.1
Accumulated Other Comprehensive Income (Loss)	(12.7)	(13.8)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,541.9	2,352.8
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,997.2	$ 10,222.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2019	2018
OPERATING ACTIVITIES		
Net Income	$ 248.0	$ 231.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	261.6	207.1
Rent - Rockport Plant, Unit 2	58.9	—
Deferred Income Taxes	(29.9)	28.1
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(11.6)	13.5
Allowance for Equity Funds Used During Construction	(16.4)	(8.0)
Mark-to-Market of Risk Management Contracts	(1.6)	(0.3)
Amortization of Nuclear Fuel	71.6	82.6
Deferred Fuel Over/Under-Recovery, Net	(20.0)	29.6
Change in Other Noncurrent Assets	46.0	(12.0)
Change in Other Noncurrent Liabilities	13.8	46.3
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	50.5	6.5
Fuel, Materials and Supplies	(4.6)	(1.1)
Accounts Payable	(7.3)	(34.7)
Accrued Taxes, Net	(49.4)	(7.1)
Payments for Rockport Plant, Unit 2 Operating Lease	(36.9)	—
Other Current Assets	7.8	4.9
Other Current Liabilities	(49.7)	(15.7)
Net Cash Flows from Operating Activities	530.8	571.3
INVESTING ACTIVITIES		
Construction Expenditures	(431.7)	(434.5)
Change in Advances to Affiliates, Net	(0.5)	(60.1)
Purchases of Investment Securities	(915.7)	(1,589.0)
Sales of Investment Securities	871.4	1,550.9
Acquisitions of Nuclear Fuel	(91.9)	(26.1)
Other Investing Activities	10.5	9.2
Net Cash Flows Used for Investing Activities	(557.9)	(549.6)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	62.9	1,168.1
Change in Advances from Affiliates, Net	101.3	(211.6)
Retirement of Long-term Debt – Nonaffiliated	(73.6)	(856.1)
Principal Payments for Finance Lease Obligations	(4.0)	(7.3)
Dividends Paid on Common Stock	(60.0)	(105.5)
Other Financing Activities	0.6	(9.0)
Net Cash Flows from (Used for) Financing Activities	27.2	(21.4)
Net Increase in Cash and Cash Equivalents	0.1	0.3
Cash and Cash Equivalents at Beginning of Period	2.4	1.3
Cash and Cash Equivalents at End of Period	$ 2.5	$ 1.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 98.7	$ 104.4

Net Cash Paid (Received) for Income Taxes	40.2	(26.5)
Noncash Acquisitions Under Finance Leases	8.1	4.4
Construction Expenditures Included in Current Liabilities as of September 30,	76.3	66.4
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	—	12.1
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	—	2.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

OHIO POWER COMPANY AND SUBSIDIARIES

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions of KWhs)			
Retail:				
Residential	4,120	4,055	11,034	11,475
Commercial	4,067	3,971	11,072	11,146
Industrial	3,689	3,688	10,936	11,066
Miscellaneous	26	27	83	84
Total Retail (a)(b)	11,902	11,741	33,125	33,771
Wholesale (c)	453	634	1,531	1,835
Total KWhs	12,355	12,375	34,656	35,606

(a) 2018 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(b) Represents energy delivered to distribution customers.
(c) Primarily Ohio’s contractually obligated purchases of OVEC power sold to 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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in degree days)			
Actual – Heating (a)	—	—	2,006	2,158
Normal – Heating (b)	6	6	2,072	2,076
Actual – Cooling (c)	872	864	1,176	1,322
Normal – Cooling (b)	672	670	973	964

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

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Net Income
(in millions)

Third Quarter of 2018	$	88.7
Changes in Gross Margin:		
Retail Margins		(2.9)
Margins from Off-system Sales		(12.2)
Transmission Revenues		0.5
Other Revenues		1.7
Total Change in Gross Margin		(12.9)
Changes in Expenses and Other:		
Other Operation and Maintenance		23.7
Depreciation and Amortization		13.0
Taxes Other Than Income Taxes		(5.1)
Carrying Costs Income		0.1
Allowance for Equity Funds Used During Construction		2.8
Non-Service Cost Components of Net Periodic Benefit Cost		(0.1)
Interest Expense		(1.8)
Total Change in Expenses and Other		32.6
Income Tax Expense (Benefit)		(39.3)
Third Quarter of 2019	$	69.1

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

- **Retail Margins** decreased $3 million primarily due to the following:
  - A $28 million net decrease in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $13 million decrease in Deferred Asset Phase-In-Recovery Rider revenues which ended in the second quarter of 2019. This decrease was offset in Depreciation and Amortization expenses below.
  - An $8 million net decrease in margin for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $6 million decrease in revenues associated with a vegetation management rider. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $6 million net decrease in margin for the Phase-In-Recovery Rider including associated amortizations which ended in the first quarter of 2019.

  These decreases were partially offset by:
  - A $27 million net increase primarily due to 2018 adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement and changes in tax riders. This increase was partially offset in Income Tax Expense (Benefit) below.
  - A $12 million increase due to the recovery of higher current year losses from a power contract with OVEC. This increase was offset in Margins from Off-system Sales below.
  - A $9 million increase in revenues associated with smart grid riders. This increase was partially offset in other expense items below.
  - A $4 million increase in rider revenues associated with the DIR. This decrease was partially offset in other expense items below.
  - A $3 million increase in Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset in Other Operation and Maintenance expenses below.

- **Margins from Off-system Sales** decreased $12 million primarily due to higher current year losses from a power contract with OVEC and lower deferrals as a result of the OVEC PPA rider. This decrease was offset in Retail Margins above.

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

- **Other Operation and Maintenance** expenses decreased $24 million primarily due to the following:
  - A $26 million decrease in recoverable PJM expenses. This decrease was offset in Gross Margin above.
  - A $5 million decrease in recoverable distribution expenses related to vegetation management. This decrease was partially offset in Retail Margins above.
  - A $4 million decrease due to higher charitable contributions in 2018.

  These decreases were partially offset by:
  - A $13 million increase in PJM expenses primarily related to the annual formula rate true-up.
- **Depreciation and Amortization** expenses decreased $13 million primarily due to the following:
  - An $8 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.
  - A $6 million decrease in recoverable DIR depreciation expense. This decrease was partially offset in Retail Margins above.

  These decreases were partially offset by:
  - A $4 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- **Taxes Other Than Income Taxes** increased $5 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Income Tax Expense (Benefit)** increased $39 million primarily due to a one-time recognition of increased amortization of Excess ADIT not subject to normalization requirements as a result of the 2018 Ohio Tax Reform Settlement. This increase was partially offset in Retail Margins above.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Net Income
(in millions)

Nine Months Ended September 30, 2018	$	237.1
Changes in Gross Margin:		
Retail Margins		9.2
Margins from Off-system Sales		(20.8)
Transmission Revenues		5.9
Other Revenues		6.0
Total Change in Gross Margin		0.3
Changes in Expenses and Other:		
Other Operation and Maintenance		28.7
Depreciation and Amortization		23.5
Taxes Other Than Income Taxes		(15.9)
Interest Income		0.1
Carrying Costs Income		(0.8)
Allowance for Equity Funds Used During Construction		6.3
Non-Service Cost Components of Net Periodic Benefit Cost		(0.6)
Interest Expense		(1.5)
Total Change in Expenses and Other		39.8
Income Tax Expense (Benefit)		(29.5)
Nine Months Ended September 30, 2019	$	247.7

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 $9 million primarily due to the following:
  - A $58 million increase due to a reversal of a regulatory provision.
  - A $33 million net increase due to 2018 adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement and changes in tax riders. This increase was partially offset in Income Tax Expense (Benefit) below.
  - A $31 million increase in revenues associated with smart grid riders. This increase was partially offset in other expense items below.
  - A $21 million increase due to the recovery of higher current year losses from a power contract with OVEC. This increase was offset in Margins from Off-system Sales below.
  - A $9 million increase in Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset in Other Operation and Maintenance expenses below.

  These increases were partially offset by:
  - A $71 million net decrease in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - An $18 million decrease in revenues associated with a vegetation management rider. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $16 million net decrease in margin for the Phase-In-Recovery Rider including associated amortizations which ended in the first quarter of 2019.
  - A $13 million decrease in Deferred Asset Phase-In-Recovery Rider revenues which ended in the second quarter of 2019. This decrease was offset in Depreciation and Amortization expenses below.

  - A $12 million net decrease in margin for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - An $8 million decrease in usage primarily in the residential and commercial classes.
  - A $4 million decrease in rider revenues associated with the DIR. This decrease was partially offset in other expense items below.
- **Margins from Off-system Sales** decreased $21 million primarily due to higher current year losses from a power contract with OVEC as a result of the OVEC PPA rider. This decrease was offset in Retail Margins above.
- **Transmission Revenues** increased $6 million primarily due to 2018 provisions for refunds, partially offset by the annual PJM Transmission formula rate true-up.
- **Other Revenues** increased $6 million primarily due to distribution connection fees and pole attachment revenues.

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

- **Other Operation and Maintenance** expenses decreased $29 million primarily due to the following:
  - A $78 million decrease in recoverable PJM expenses. This decrease was offset in Gross Margin above.
  - A $10 million decrease in recoverable distribution expenses related to vegetation management. This decrease was partially offset in Retail Margins above.

  These decreases were partially offset by:
  - A $57 million increase in PJM expenses primarily related to the annual formula rate true-up.
- **Depreciation and Amortization** expenses decreased $24 million primarily due to the following:
  - A $30 million decrease in recoverable DIR depreciation expense. This decrease was partially offset in Retail Margins above.
  - An $11 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.

  This decrease was offset by:
  - A $17 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- **Taxes Other Than Income Taxes** increased $16 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Allowance for Equity Funds Used During Construction** increased $6 million primarily due to adjustments that resulted from 2019 FERC audit findings.
- **Income Tax Expense (Benefit)** increased $30 million primarily due to a one-time recognition of increased amortization of Excess ADIT not subject to normalization requirements as a result of the 2018 Ohio Tax Reform Settlement. This increase was partially offset in Retail Margins above.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
REVENUES				
Electricity, Transmission and Distribution	$ 698.6	$ 772.6	$ 2,127.4	$ 2,294.8
Sales to AEP Affiliates	9.0	3.3	18.2	17.9
Other Revenues	3.0	2.4	8.4	5.3
TOTAL REVENUES	710.6	778.3	2,154.0	2,318.0
EXPENSES				
Purchased Electricity for Resale	158.3	166.3	454.0	534.7
Purchased Electricity from AEP Affiliates	40.6	39.3	120.4	97.4
Amortization of Generation Deferrals	8.8	56.9	65.3	171.9
Other Operation	194.9	215.2	565.7	586.4
Maintenance	40.0	43.4	106.7	114.7
Depreciation and Amortization	57.4	70.4	176.8	200.3
Taxes Other Than Income Taxes	112.0	106.9	326.9	311.0
TOTAL EXPENSES	612.0	698.4	1,815.8	2,016.4
OPERATING INCOME	98.6	79.9	338.2	301.6
Other Income (Expense):				
Interest Income	0.8	0.8	2.7	2.6
Carrying Costs Income	0.3	0.2	0.7	1.5
Allowance for Equity Funds Used During Construction	4.8	2.0	14.1	7.8
Non-Service Cost Components of Net Periodic Benefit Cost	3.7	3.8	11.0	11.6
Interest Expense	(27.9)	(26.1)	(78.1)	(76.6)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	80.3	60.6	288.6	248.5
Income Tax Expense (Benefit)	11.2	(28.1)	40.9	11.4
NET INCOME	$ 69.1	$ 88.7	$ 247.7	$ 237.1

The common stock of OPCo is wholly-owned by Parent.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
Net Income	$ 69.1	$ 88.7	$ 247.7	$ 237.1
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2019 and 2018, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2019 and 2018, Respectively	(0.3)	(0.4)	(1.0)	(1.0)
TOTAL COMPREHENSIVE INCOME	$ 68.8	$ 88.3	$ 246.7	$ 236.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 321.2	$ 838.8	$ 1,148.4	$ 1.9	$ 2,310.3
Common Stock Dividends			(112.5)		(112.5)
ASU 2018-02 Adoption				0.4	0.4
Net Income			79.6		79.6
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	321.2	838.8	1,115.5	2.0	2,277.5
Common Stock Dividends			(112.5)		(112.5)
Net Income			68.8		68.8
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	321.2	838.8	1,071.8	1.7	2,233.5
Common Stock Dividends			(112.5)		(112.5)
Net Income			88.7		88.7
Other Comprehensive Loss				(0.4)	(0.4)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 321.2	$ 838.8	$ 1,048.0	$ 1.3	$ 2,209.3
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 321.2	$ 838.8	$ 1,136.4	$ 1.0	$ 2,297.4
Common Stock Dividends			(25.0)		(25.0)
Net Income			128.0		128.0
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	321.2	838.8	1,239.4	0.7	2,400.1
Common Stock Dividends			(60.0)		(60.0)
Net Income			50.6		50.6
Other Comprehensive Loss				(0.4)	(0.4)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	321.2	838.8	1,230.0	0.3	2,390.3
Net Income			69.1		69.1
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2019	$ 321.2	$ 838.8	$ 1,299.1	$ —	$ 2,459.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4.7	$ 4.9
Restricted Cash for Securitized Funding	—	27.6
Accounts Receivable:		
Customers	35.4	111.1
Affiliated Companies	56.2	70.8
Accrued Unbilled Revenues	26.5	21.4
Miscellaneous	0.3	0.3
Allowance for Uncollectible Accounts	(2.1)	(1.0)
Total Accounts Receivable	116.3	202.6
Materials and Supplies	48.5	42.9
Renewable Energy Credits	41.5	25.9
Prepayments and Other Current Assets	19.8	15.7
TOTAL CURRENT ASSETS	230.8	319.6
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,613.0	2,544.3
Distribution	5,192.8	4,942.3
Other Property, Plant and Equipment	662.3	574.8
Construction Work in Progress	485.3	432.1
Total Property, Plant and Equipment	8,953.4	8,493.5
Accumulated Depreciation and Amortization	2,256.1	2,218.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,697.3	6,274.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	372.2	387.5
Securitized Assets	—	12.9
Deferred Charges and Other Noncurrent Assets	320.3	441.0
TOTAL OTHER NONCURRENT ASSETS	692.5	841.4
TOTAL ASSETS	$ 7,620.6	$ 7,435.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2019 and December 31, 2018
(dollars in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT LIABILITIES		
Advances from Affiliates	$ 17.6	$ 114.1
Accounts Payable:		
General	203.1	211.9
Affiliated Companies	100.2	102.9
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2019 and December 31, 2018 Amounts Include $0 and $47.8, Respectively, Related to Ohio Phase-in-Recovery Funding)	0.1	47.9
Risk Management Liabilities	7.2	5.8
Customer Deposits	88.2	113.1
Accrued Taxes	294.3	537.8
Accrued Interest	44.7	31.4
Obligations Under Operating Leases	12.8	—
Other Current Liabilities	99.4	182.8
TOTAL CURRENT LIABILITIES	867.6	1,347.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,113.8	1,668.7
Long-term Risk Management Liabilities	105.7	93.8
Deferred Income Taxes	805.0	763.3
Regulatory Liabilities and Deferred Investment Tax Credits	1,143.6	1,221.2
Obligations Under Operating Leases	75.9	—
Deferred Credits and Other Noncurrent Liabilities	49.9	43.8
TOTAL NONCURRENT LIABILITIES	4,293.9	3,790.8
TOTAL LIABILITIES	5,161.5	5,138.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	1,299.1	1,136.4
Accumulated Other Comprehensive Income (Loss)	—	1.0
TOTAL COMMON SHAREHOLDER'S EQUITY	2,459.1	2,297.4
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,620.6	$ 7,435.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2019	2018
OPERATING ACTIVITIES		
Net Income	$ 247.7	$ 237.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	176.8	200.3
Amortization of Generation Deferrals	65.3	171.9
Deferred Income Taxes	16.8	(71.9)
Allowance for Equity Funds Used During Construction	(14.1)	(7.8)
Mark-to-Market of Risk Management Contracts	13.3	(37.1)
Property Taxes	197.7	191.1
Refund of Global Settlement	(12.4)	(5.5)
Reversal of Regulatory Provision	(56.2)	—
Change in Regulatory Assets	(28.1)	180.9
Change in Other Noncurrent Assets	(19.4)	0.8
Change in Other Noncurrent Liabilities	(51.1)	62.5
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	90.0	21.3
Materials and Supplies	(9.6)	(3.7)
Accounts Payable	(12.3)	(31.8)
Accrued Taxes, Net	(245.9)	(210.6)
Other Current Assets	(9.0)	7.6
Other Current Liabilities	(40.0)	(4.3)
Net Cash Flows from Operating Activities	309.5	700.8
INVESTING ACTIVITIES		
Construction Expenditures	(570.6)	(538.5)
Other Investing Activities	20.0	15.5
Net Cash Flows Used for Investing Activities	(550.6)	(523.0)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	444.3	392.8
Change in Advances from Affiliates, Net	(96.5)	155.1
Retirement of Long-term Debt – Nonaffiliated	(48.0)	(397.0)
Principal Payments for Finance Lease Obligations	(2.6)	(2.9)
Dividends Paid on Common Stock	(85.0)	(337.5)
Other Financing Activities	1.1	0.7
Net Cash Flows from (Used for) Financing Activities	213.3	(188.8)
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(27.8)	(11.0)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	32.5	29.7
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 4.7	$ 18.7
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 61.3	$ 67.3
Net Cash Paid for Income Taxes	25.7	54.1
Noncash Acquisitions Under Finance Leases	8.6	3.0
Construction Expenditures Included in Current Liabilities as of September 30,	99.9	66.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

PUBLIC SERVICE COMPANY OF OKLAHOMA

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions of KWhs)			
Retail:				
Residential	2,172	2,005	4,981	5,133
Commercial	1,497	1,433	3,818	3,864
Industrial	1,642	1,604	4,665	4,559
Miscellaneous	378	362	950	973
Total Retail (a)	5,689	5,404	14,414	14,529
Wholesale	224	182	617	544
Total KWhs	5,913	5,586	15,031	15,073

(a) 2018 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in degree days)			
Actual – Heating (a)	—	—	1,199	1,161
Normal – Heating (b)	1	1	1,077	1,082
Actual – Cooling (c)	1,593	1,433	2,206	2,352
Normal – Cooling (b)	1,397	1,396	2,072	2,063

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

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Net Income
(in millions)

Third Quarter of 2018	$	60.4
Changes in Gross Margin:		
Retail Margins (a)		22.0
Margins from Off-system Sales		0.8
Transmission Revenues		(3.7)
Total Change in Gross Margin		19.1
Changes in Expenses and Other:		
Other Operation and Maintenance		19.5
Depreciation and Amortization		3.2
Taxes Other Than Income Taxes		(0.3)
Other Income (Expense)		1.4
Interest Expense		0.3
Total Change in Expenses and Other		24.1
Income Tax Expense		(3.3)
Third Quarter of 2019	$	100.3

(a) Includes firm wholesale sales to municipals and cooperatives.

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 $22 million primarily due to the following:
  - A $14 million increase due to new base rates implemented in April 2019.
  - A $9 million increase in weather-related usage due to an 11% increase in cooling degree days.
  - A $5 million increase in weather-normalized margins.

  These increases were partially offset by:
  - A $7 million decrease due to customer refunds related to Tax Reform. This decrease was partially offset in Income Tax Expense below.
- **Transmission Revenues** decreased $4 million primarily due to a decrease in SPP Base Plan Funding revenues.

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

- **Other Operation and Maintenance** expenses decreased $20 million primarily due the following:
  - A $9 million decrease in transmission expenses primarily due to decreased SPP transmission services.
  - A $5 million decrease in Energy Efficiency program costs due to a change in amortizations of costs approved by the OCC. This decrease was offset in Retail Margins above.
  - A $3 million decrease due to Wind Catcher Project expenses incurred in 2018.
- **Depreciation and Amortization** expenses decreased $3 million primarily due to the refund of Excess ADIT.
- **Income Tax Expense** increased $3 million primarily due to an increase in pretax book income partially offset by an increase in amortization of Excess ADIT. The amortization of Excess ADIT was partially offset in Gross Margin above.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Net Income
(in millions)

Nine Months Ended September 30, 2018	$	89.8
Changes in Gross Margin:		
Retail Margins (a)		2.2
Margin from Off-system Sales		0.9
Transmission Revenues		(5.6)
Other Revenues		1.8
Total Change in Gross Margin		(0.7)
Changes in Expenses and Other:		
Other Operation and Maintenance		63.9
Depreciation and Amortization		(4.9)
Taxes Other Than Income Taxes		(0.4)
Other Income (Expense)		2.4
Non-Service Cost Components of Net Periodic Benefit Cost		(0.2)
Interest Expense		(2.9)
Total Change in Expenses and Other		57.9
Income Tax Expense		1.4
Nine Months Ended September 30, 2019	$	148.4

(a) Includes firm wholesale sales to municipals and cooperatives.

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

- **Retail Margins** increased $2 million primarily due to the following:
  - A $35 million increase due to new base rates implemented in April 2019 and March 2018.

  This increase was partially offset by:
  - A $13 million decrease due to customer refunds related to Tax Reform. This decrease was partially offset in Income Tax Expense below.
  - An $11 million decrease in weather-related usage due to a 6% decrease in cooling degree days.
  - A $10 million decrease in weather-normalized margins.
- **Transmission Revenues** decreased $6 million primarily due to a decrease in SPP Base Plan Funding revenues.

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

- **Other Operation and Maintenance** expenses decreased $64 million primarily due to the following:
  - A $31 million decrease in transmission expenses primarily due to decreased SPP transmission services.
  - A $17 million decrease in Energy Efficiency program costs due to a change in amortizations of costs approved by the OCC. This decrease was offset in Retail Margins above.
  - A $12 million decrease due to Wind Catcher Project expenses incurred in 2018.
- **Depreciation and Amortization** expenses increased $5 million primarily due to the following:
  - An $8 million increase due to a higher depreciable base and new rates implemented in March 2018.

  This increase was partially offset by:
  - A $3 million decrease due to the refund of Excess ADIT.
- **Income Tax Expense** decreased $1 million primarily due to an increase in amortization of Excess ADIT partially offset by an increase in pretax book income. This decrease was partially offset in Gross Margin above.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
REVENUES				
Electric Generation, Transmission and Distribution	$ 490.5	$ 479.1	$ 1,164.3	$ 1,209.5
Sales to AEP Affiliates	1.3	1.1	5.0	3.7
Other Revenues	1.2	1.2	4.6	3.3
TOTAL REVENUES	493.0	481.4	1,173.9	1,216.5
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	98.4	104.4	181.2	211.5
Purchased Electricity for Resale	115.3	116.8	340.7	352.3
Other Operation	87.6	106.3	226.0	286.8
Maintenance	21.5	22.3	70.1	73.2
Depreciation and Amortization	39.1	42.3	125.4	120.5
Taxes Other Than Income Taxes	11.1	10.8	33.0	32.6
TOTAL EXPENSES	373.0	402.9	976.4	1,076.9
OPERATING INCOME	120.0	78.5	197.5	139.6
Other Income (Expense):				
Other Income (Expense)	1.2	(0.2)	2.1	(0.3)
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	2.1	6.3	6.5
Interest Expense	(16.1)	(16.4)	(50.3)	(47.4)
INCOME BEFORE INCOME TAX EXPENSE	107.2	64.0	155.6	98.4
Income Tax Expense	6.9	3.6	7.2	8.6
NET INCOME	$ 100.3	$ 60.4	$ 148.4	$ 89.8

The common stock of PSO is wholly-owned by Parent.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
Net Income	$ 100.3	$ 60.4	$ 148.4	$ 89.8
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2019 and 2018, Respectively, and $(0.2) and $(0.2) for the Nine Months Ended September 30, 2019 and 2018, Respectively	(0.2)	(0.2)	(0.7)	(0.7)
TOTAL COMPREHENSIVE INCOME	$ 100.1	$ 60.2	$ 147.7	$ 89.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	$ 157.2	$ 364.0	$ 691.5	$ 2.6	$ 1,215.3
Common Stock Dividends			(12.5)		(12.5)
ASU 2018-02 Adoption				0.5	0.5
Net Loss			(7.2)		(7.2)
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2018	157.2	364.0	671.8	2.9	1,195.9
Common Stock Dividends			(12.5)		(12.5)
Net Income			36.6		36.6
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2018	157.2	364.0	695.9	2.6	1,219.7
Common Stock Dividends			(12.5)		(12.5)
Net Income			60.4		60.4
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2018	$ 157.2	$ 364.0	$ 743.8	$ 2.4	$ 1,267.4
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 157.2	$ 364.0	$ 724.7	$ 2.1	$ 1,248.0
Common Stock Dividends			(11.3)		(11.3)
Net Income			6.2		6.2
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	157.2	364.0	719.6	1.9	1,242.7
Net Income			41.9		41.9
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	157.2	364.0	761.5	1.6	1,284.3
Net Income			100.3		100.3
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2019	$ 157.2	$ 364.0	$ 861.8	$ 1.4	$ 1,384.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.9	$ 2.0
Advances to Affiliates	95.1	—
Accounts Receivable:		
Customers	25.2	32.5
Affiliated Companies	27.3	26.2
Miscellaneous	4.0	5.7
Allowance for Uncollectible Accounts	(0.4)	(0.1)
Total Accounts Receivable	56.1	64.3
Fuel	12.8	12.3
Materials and Supplies	46.2	44.8
Risk Management Assets	21.7	10.4
Accrued Tax Benefits	17.0	14.7
Prepayments and Other Current Assets	11.5	9.4
TOTAL CURRENT ASSETS	263.3	157.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,569.9	1,577.0
Transmission	928.4	892.3
Distribution	2,650.1	2,572.8
Other Property, Plant and Equipment	319.6	303.5
Construction Work in Progress	128.8	94.0
Total Property, Plant and Equipment	5,596.8	5,439.6
Accumulated Depreciation and Amortization	1,558.5	1,472.9
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,038.3	3,966.7
OTHER NONCURRENT ASSETS		
Regulatory Assets	380.7	369.0
Employee Benefits and Pension Assets	32.6	31.7
Operating Lease Assets	37.1	—
Deferred Charges and Other Noncurrent Assets	17.2	7.1
TOTAL OTHER NONCURRENT ASSETS	467.6	407.8
TOTAL ASSETS	$ 4,769.2	$ 4,532.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2019 and December 31, 2018
(Unaudited)

	September 30, 2019	December 31, 2018
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 105.5
Accounts Payable:		
General	128.6	126.9
Affiliated Companies	38.6	47.1
Long-term Debt Due Within One Year – Nonaffiliated	138.2	375.5
Risk Management Liabilities	0.3	1.0
Customer Deposits	59.0	58.6
Accrued Taxes	43.7	22.4
Obligations Under Operating Leases	6.0	—
Regulatory Liability for Over-Recovered Fuel Costs	69.9	20.1
Other Current Liabilities	67.7	64.5
TOTAL CURRENT LIABILITIES	552.0	821.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,248.2	911.5
Deferred Income Taxes	617.5	607.8
Regulatory Liabilities and Deferred Investment Tax Credits	858.9	864.7
Asset Retirement Obligations	50.9	46.3
Obligations Under Operating Leases	31.2	—
Deferred Credits and Other Noncurrent Liabilities	26.1	32.5
TOTAL NONCURRENT LIABILITIES	2,832.8	2,462.8
TOTAL LIABILITIES	3,384.8	3,284.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157.2	157.2
Paid-in Capital	364.0	364.0
Retained Earnings	861.8	724.7
Accumulated Other Comprehensive Income (Loss)	1.4	2.1
TOTAL COMMON SHAREHOLDER'S EQUITY	1,384.4	1,248.0
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 4,769.2	$ 4,532.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2019	2018
OPERATING ACTIVITIES		
Net Income	$ 148.4	$ 89.8
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	125.4	120.5
Deferred Income Taxes	(9.7)	(13.4)
Allowance for Equity Funds Used During Construction	(1.5)	0.3
Mark-to-Market of Risk Management Contracts	(12.0)	(11.5)
Property Taxes	(9.6)	(9.6)
Deferred Fuel Over/Under-Recovery, Net	49.8	73.3
Change in Other Noncurrent Assets	4.6	6.9
Change in Other Noncurrent Liabilities	(0.2)	14.6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	9.1	(3.4)
Fuel, Materials and Supplies	(1.9)	(1.5)
Accounts Payable	(5.8)	6.9
Accrued Taxes, Net	19.0	38.4
Other Current Assets	(2.4)	0.3
Other Current Liabilities	1.1	15.1
Net Cash Flows from Operating Activities	314.3	326.7
INVESTING ACTIVITIES		
Construction Expenditures	(198.7)	(162.8)
Change in Advances to Affiliates, Net	(95.1)	—
Other Investing Activities	2.1	3.9
Net Cash Flows Used for Investing Activities	(291.7)	(158.9)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	349.8	—
Change in Advances from Affiliates, Net	(105.5)	(127.6)
Retirement of Long-term Debt – Nonaffiliated	(250.4)	(0.3)
Make Whole Premium on Extinguishment of Long-term Debt	(3.0)	—
Principal Payments for Finance Lease Obligations	(2.2)	(2.5)
Dividends Paid on Common Stock	(11.3)	(37.5)
Other Financing Activities	0.9	0.4
Net Cash Flows Used for Financing Activities	(21.7)	(167.5)
Net Increase in Cash and Cash Equivalents	0.9	0.3
Cash and Cash Equivalents at Beginning of Period	2.0	1.6
Cash and Cash Equivalents at End of Period	$ 2.9	$ 1.9
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 46.5	$ 42.0
Net Cash Paid for Income Taxes	16.0	1.6
Noncash Acquisitions Under Finance Leases	3.4	2.3
Construction Expenditures Included in Current Liabilities as of September 30,	31.5	24.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions of KWhs)			
Retail:				
Residential	2,071	1,992	4,896	5,156
Commercial	1,746	1,675	4,430	4,548
Industrial	1,414	1,366	4,020	4,033
Miscellaneous	19	19	59	59
Total Retail (a)	5,250	5,052	13,405	13,796
Wholesale	1,831	1,881	5,317	5,352
Total KWhs	7,081	6,933	18,722	19,148

(a) 2018 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in degree days)			
Actual – Heating (a)	—	—	732	784
Normal – Heating (b)	1	1	725	733
Actual – Cooling (c)	1,552	1,453	2,263	2,408
Normal – Cooling (b)	1,408	1,408	2,187	2,179

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

Third Quarter of 2019 Compared to Third Quarter of 2018

Reconciliation of Third Quarter of 2018 to Third Quarter of 2019
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2018	$	88.2
Changes in Gross Margin:		
Retail Margins (a)		10.7
Off-system Sales		(0.2)
Transmission Revenues		(4.8)
Other Revenues		(0.4)
Total Change in Gross Margin		5.3
Changes in Expenses and Other:		
Other Operation and Maintenance		4.9
Depreciation and Amortization		(3.3)
Taxes Other Than Income Taxes		0.7
Interest Income		(0.5)
Allowance for Equity Funds Used During Construction		1.0
Non-Service Cost Components of Net Periodic Benefit Cost		(0.2)
Interest Expense		3.5
Total Change in Expenses and Other		6.1
Income Tax Expense (Benefit)		10.3
Net Income Attributable to Noncontrolling Interest		0.6
Third Quarter of 2019	$	110.5

(a) Includes firm wholesale sales to municipals and cooperatives.

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 $11 million primarily due to the following:
  - A $6 million increase in weather-normalized margins.
  - A $5 million increase in weather-related usage primarily due to a 7% increase in cooling degree days.
- **Transmission Revenues** decreased $ 5 million primarily due to a decrease in SPP Base Plan Funding revenues and a decrease in nonaffiliated transmission services.

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

- **Other Operation and Maintenance** expenses decreased $5 million primarily due to Wind Catcher Project expenses incurred in 2018.
- **Depreciation and Amortization** expenses increased $3 million primarily due to a higher depreciable base.
- **Interest Expense** decreased $4 million primarily due to lower interest rates on outstanding long-term debt.
- **Income Tax Expense (Benefit)** decreased $10 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements. This decrease was partially offset in Gross Margin above.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Reconciliation of Nine Months Ended September 30, 2018 to Nine Months Ended September 30, 2019
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2018	$	137.6
Changes in Gross Margin:		
Retail Margins (a)		(18.3)
Off-system Sales		(0.1)
Transmission Revenues		(35.6)
Other Revenues		(0.3)
Total Change in Gross Margin		(54.3)
Changes in Expenses and Other:		
Other Operation and Maintenance		47.7
Depreciation and Amortization		(11.2)
Taxes Other Than Income Taxes		0.4
Interest Income		(1.5)
Allowance for Equity Funds Used During Construction		0.7
Non-Service Cost Components of Net Periodic Benefit Cost		(0.5)
Interest Expense		6.4
Total Change in Expenses and Other		42.0
Income Tax Expense (Benefit)		17.9
Equity Earnings of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interest		1.0
Nine Months Ended September 30, 2019	$	144.5

(a) Includes firm wholesale sales to municipals and cooperatives.

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

- **Retail Margins** decreased $18 million primarily due to the following:
  - A $14 million decrease in weather-related usage primarily due to a 6% decrease in cooling degree days and a 7% decrease in heating degree days.
  - A $10 million decrease in weather-normalized margins.

  These decreases were partially offset by:
  - A $7 million increase primarily due to rider and base rate revenue increases in Louisiana. This increase was offset in other expense items below.
- **Transmission Revenues** decreased $36 million primarily due to the following:
  - A $40 million decrease in the annual SPP formula rate true-up.
  - A $7 million decrease primarily due to a reduction in SPP Base Plan Funding revenues.

  These decreases were partially offset by:
  - An $11 million increase due to a provision for refund recorded in 2018 related to certain transmission assets that management believes should not have been included in the SPP formula rate.

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

- **Other Operation and Maintenance** expenses decreased $48 million primarily due to the following:
  - A $28 million decrease due to Wind Catcher Project expenses incurred in 2018.
  - A $24 million decrease in affiliated SPP transmission expenses primarily due to the annual formula rate true-up.

  These decreases were partially offset by:
  - A $7 million increase in overhead line expenses primarily related to storm restoration.
- **Depreciation and Amortization** expenses increased $11 million primarily due to higher depreciation rates implemented in the third quarter of 2018 and a higher depreciable base.
- **Interest Expense** decreased $6 million primarily due to lower interest rates on outstanding long-term debt.
- **Income Tax Expense (Benefit)** decreased $18 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements and a decrease in pretax book income. This decrease was partially offset in Gross Margin above.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	**2018**	**2019**	**2018**
REVENUES				
Electric Generation, Transmission and Distribution	$ 536.5	$ 526.0	$ 1,344.8	$ 1,390.4
Sales to AEP Affiliates	8.8	8.7	21.6	20.2
Provision for Refund – Affiliated	(0.1)	—	(25.3)	—
Other Revenues	0.3	0.6	1.0	1.2
TOTAL REVENUES	545.5	535.3	1,342.1	1,411.8
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	148.8	152.1	400.2	393.4
Purchased Electricity for Resale	44.8	36.6	110.5	132.7
Other Operation	91.9	99.1	242.4	292.0
Maintenance	35.9	33.6	104.1	102.2
Depreciation and Amortization	63.2	59.9	187.1	175.9
Taxes Other Than Income Taxes	26.2	26.9	76.0	76.4
TOTAL EXPENSES	410.8	408.2	1,120.3	1,172.6
OPERATING INCOME	134.7	127.1	221.8	239.2
Other Income (Expense):				
Interest Income	0.6	1.1	2.0	3.5
Allowance for Equity Funds Used During Construction	1.6	0.6	4.5	3.8
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	2.3	6.4	6.9
Interest Expense	(29.2)	(32.7)	(89.4)	(95.8)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	109.8	98.4	145.3	157.6
Income Tax Expense (Benefit)	(0.7)	9.6	—	17.9
Equity Earnings of Unconsolidated Subsidiary	0.8	0.8	2.3	2.0
NET INCOME	111.3	89.6	147.6	141.7
Net Income Attributable to Noncontrolling Interest	0.8	1.4	3.1	4.1
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 110.5	$ 88.2	$ 144.5	$ 137.6

The common stock of SWEPCo is wholly-owned by Parent.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Net Income	$ 111.3	$ 89.6	$ 147.6	$ 141.7
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.8 for the Three Months Ended September 30, 2019 and 2018, Respectively, and $0.3 and $1 for the Nine Months Ended September 30, 2019 and 2018, Respectively	0.3	2.7	1.1	3.6
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $(0.1) for the Three Months Ended September 30, 2019 and 2018, Respectively, and $(0.2) and $(0.3) for the Nine Months Ended September 30, 2019 and 2018, Respectively	(0.3)	(0.3)	(0.9)	(1.0)
TOTAL OTHER COMPREHENSIVE INCOME	—	2.4	0.2	2.6
TOTAL COMPREHENSIVE INCOME	111.3	92.0	147.8	144.3
Total Comprehensive Income Attributable to Noncontrolling Interest	0.8	1.4	3.1	4.1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 110.5	$ 90.6	$ 144.7	$ 140.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2017	$ 135.7	$ 676.6	$ 1,426.6	$ (4.0)	$ (0.4)	$ 2,234.5
Common Stock Dividends			(20.0)			(20.0)
Common Stock Dividends – Nonaffiliated					(0.8)	(0.8)
ASU 2018-02 Adoption			(0.4)	(0.9)		(1.3)
Net Income			11.8		1.6	13.4
Other Comprehensive Income				0.1		0.1
TOTAL EQUITY – MARCH 31, 2018	135.7	676.6	1,418.0	(4.8)	0.4	2,225.9
Common Stock Dividends			(20.0)			(20.0)
Common Stock Dividends – Nonaffiliated					(1.0)	(1.0)
Net Income			37.6		1.1	38.7
Other Comprehensive Income				0.1		0.1
TOTAL EQUITY – JUNE 30, 2018	135.7	676.6	1,435.6	(4.7)	0.5	2,243.7
Common Stock Dividends			(20.0)			(20.0)
Common Stock Dividends – Nonaffiliated					(1.4)	(1.4)
Net Income			88.2		1.4	89.6
Other Comprehensive Income				2.4		2.4
TOTAL EQUITY – SEPTEMBER 30, 2018	$ 135.7	$ 676.6	$ 1,503.8	$ (2.3)	$ 0.5	$ 2,314.3
TOTAL EQUITY – DECEMBER 31, 2018	$ 135.7	$ 676.6	$ 1,508.4	$ (5.4)	$ 0.3	$ 2,315.6
Common Stock Dividends			(18.7)			(18.7)
Common Stock Dividends – Nonaffiliated					(1.1)	(1.1)
Net Income			27.8		1.2	29.0
Other Comprehensive Income				0.1		0.1
TOTAL EQUITY – MARCH 31, 2019	135.7	676.6	1,517.5	(5.3)	0.4	2,324.9
Common Stock Dividends			(18.8)			(18.8)
Common Stock Dividends – Nonaffiliated					(1.1)	(1.1)
Net Income			6.2		1.1	7.3
Other Comprehensive Income				0.1		0.1
TOTAL EQUITY – JUNE 30, 2019	135.7	676.6	1,504.9	(5.2)	0.4	2,312.4
Common Stock Dividends – Nonaffiliated					(1.1)	(1.1)
Net Income			110.5		0.8	111.3
TOTAL EQUITY – SEPTEMBER 30, 2019	$ 135.7	$ 676.6	$ 1,615.4	$ (5.2)	$ 0.1	$ 2,422.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2019 and December 31, 2018
(in millions)
(Unaudited)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents (September 30, 2019 and December 31, 2018 Amounts Include $18.2 and $22, Respectively, Related to Sabine)	$ 21.4	$ 24.5
Advances to Affiliates	8.5	83.4
Accounts Receivable:		
Customers	20.6	24.5
Affiliated Companies	56.8	28.8
Miscellaneous	16.6	20.2
Allowance for Uncollectible Accounts	(1.4)	(0.7)
Total Accounts Receivable	92.6	72.8
Fuel (September 30, 2019 and December 31, 2018 Amounts Include $51.6 and $35.7, Respectively, Related to Sabine)	135.9	120.5
Materials and Supplies	69.8	67.5
Risk Management Assets	9.4	4.8
Regulatory Asset for Under-Recovered Fuel Costs	11.1	18.8
Prepayments and Other Current Assets	24.4	22.2
TOTAL CURRENT ASSETS	373.1	414.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,676.1	4,672.6
Transmission	1,995.9	1,866.9
Distribution	2,241.1	2,178.6
Other Property, Plant and Equipment (September 30, 2019 and December 31, 2018 Amounts Include $210.3 and $276.9, Respectively, Related to Sabine)	703.2	762.7
Construction Work in Progress	235.0	199.3
Total Property, Plant and Equipment	9,851.3	9,680.1
Accumulated Depreciation and Amortization (September 30, 2019 and December 31, 2018 Amounts Include $105.7 and $174.6, Respectively, Related to Sabine)	2,848.2	2,808.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,003.1	6,871.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	223.6	230.8
Deferred Charges and Other Noncurrent Assets	167.2	111.2
TOTAL OTHER NONCURRENT ASSETS	390.8	342.0
TOTAL ASSETS	$ 7,767.0	$ 7,628.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2019 and December 31, 2018
(Unaudited)

	September 30, 2019	December 31, 2018
	(in millions)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 127.6	$ 129.1
Affiliated Companies	62.4	64.2
Long-term Debt Due Within One Year – Nonaffiliated	121.2	59.7
Risk Management Liabilities	1.7	0.4
Customer Deposits	65.0	64.5
Accrued Taxes	94.7	42.8
Accrued Interest	22.9	34.7
Obligations Under Operating Leases	5.9	—
Regulatory Liability for Over-Recovered Fuel Costs	17.4	11.1
Other Current Liabilities	108.0	106.4
TOTAL CURRENT LIABILITIES	626.8	512.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,535.7	2,653.7
Long-term Risk Management Liabilities	3.0	2.2
Deferred Income Taxes	919.1	902.8
Regulatory Liabilities and Deferred Investment Tax Credits	918.1	923.0
Asset Retirement Obligations	200.9	191.3
Obligations Under Operating Leases	32.5	—
Deferred Credits and Other Noncurrent Liabilities	108.3	126.8
TOTAL NONCURRENT LIABILITIES	4,717.6	4,799.8
TOTAL LIABILITIES	5,344.4	5,312.7
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135.7	135.7
Paid-in Capital	676.6	676.6
Retained Earnings	1,615.4	1,508.4
Accumulated Other Comprehensive Income (Loss)	(5.2)	(5.4)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,422.5	2,315.3
Noncontrolling Interest	0.1	0.3
TOTAL EQUITY	2,422.6	2,315.6
TOTAL LIABILITIES AND EQUITY	$ 7,767.0	$ 7,628.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2019 and 2018
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
OPERATING ACTIVITIES		
Net Income	$ 147.6	$ 141.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	187.1	175.9
Deferred Income Taxes	(15.9)	2.0
Allowance for Equity Funds Used During Construction	(4.5)	(3.8)
Mark-to-Market of Risk Management Contracts	(2.5)	2.5
Property Taxes	(16.1)	(15.8)
Deferred Fuel Over/Under-Recovery, Net	14.1	4.4
Change in Other Noncurrent Assets	3.5	(8.9)
Change in Other Noncurrent Liabilities	5.8	52.1
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(17.2)	44.3
Fuel, Materials and Supplies	(17.7)	5.0
Accounts Payable	(12.8)	(29.9)
Accrued Taxes, Net	54.1	38.4
Other Current Assets	(4.5)	3.2
Other Current Liabilities	(13.9)	4.2
Net Cash Flows from Operating Activities	307.1	415.3
INVESTING ACTIVITIES		
Construction Expenditures	(277.3)	(336.6)
Change in Advances to Affiliates, Net	74.9	(516.6)
Other Investing Activities	(1.2)	1.2
Net Cash Flows Used for Investing Activities	(203.6)	(852.0)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	1,015.4
Change in Short-term Debt – Nonaffiliated	—	(2.6)
Change in Advances from Affiliates, Net	—	(118.7)
Retirement of Long-term Debt – Nonaffiliated	(58.2)	(385.3)
Principal Payments for Finance Lease Obligations	(8.1)	(8.5)
Dividends Paid on Common Stock	(37.5)	(60.0)
Dividends Paid on Common Stock – Nonaffiliated	(3.3)	(3.2)
Other Financing Activities	0.5	0.5
Net Cash Flows from (Used for) Financing Activities	(106.6)	437.6
Net Increase (Decrease) in Cash and Cash Equivalents	(3.1)	0.9
Cash and Cash Equivalents at Beginning of Period	24.5	1.6
Cash and Cash Equivalents at End of Period	$ 21.4	$ 2.5
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 95.1	$ 102.5
Net Cash Paid for Income Taxes	7.3	12.9
Noncash Acquisitions Under Finance Leases	4.7	3.2
Construction Expenditures Included in Current Liabilities as of September 30,	52.0	37.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 126.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

The condensed notes to condensed 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:

1. SIGNIFICANT ACCOUNTING MATTERS

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

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three and nine months ended September 30, 2019 is not necessarily indicative of results that may be expected for the year ending December 31, 2019. The condensed financial statements are unaudited and should be read in conjunction with the audited 2018 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 21, 2019.

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 awards.

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

	Three Months Ended September 30,			
	2019		2018	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 733.5		$ 577.6	
Weighted Average Number of Basic Shares Outstanding	493.8	$ 1.49	493.0	$ 1.17
Weighted Average Dilutive Effect of Stock-Based Awards	1.7	(0.01)	0.9	—
Weighted Average Number of Diluted Shares Outstanding	495.5	$ 1.48	493.9	$ 1.17

	Nine Months Ended September 30,			
	2019		2018	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,767.6		$ 1,560.4	
Weighted Average Number of Basic Shares Outstanding	493.6	$ 3.58	492.6	$ 3.17
Weighted Average Dilutive Effect of Stock-Based Awards	1.5	(0.01)	0.9	(0.01)
Weighted Average Number of Diluted Shares Outstanding	495.1	$ 3.57	493.5	$ 3.16

Equity Units issued in March 2019 are potentially dilutive securities but were excluded from the calculation of diluted EPS for the three and nine months ended September 30, 2019, as the dilutive stock price threshold was not met. See Note 13 - Financing Activities for more information related to Equity Units.

There were no antidilutive shares outstanding as of September 30, 2019 and 2018.

Restricted Cash (Applies to AEP, AEP Texas, APCo and OPCo)

Restricted Cash primarily included funds held by trustee for the payment of securitization bonds and contractually restricted deposits held for the future payment of the remaining construction activities at Santa Rita East.

Reconciliation of Cash, Cash Equivalents and Restricted Cash

The following tables provide a reconciliation of Cash, Cash Equivalents and Restricted Cash reported within the balance sheets that sum to the total of the same amounts shown on the statements of cash flows:

	September 30, 2019			
	AEP	**AEP Texas**	**APCo**	**OPCo**
	(in millions)			
Cash and Cash Equivalents	$ 348.8	$ 0.1	$ 3.5	$ 4.7
Restricted Cash	141.0	114.3	17.1	—
Total Cash, Cash Equivalents and Restricted Cash	$ 489.8	$ 114.4	$ 20.6	$ 4.7

	December 31, 2018			
	AEP	**AEP Texas**	**APCo**	**OPCo**
	(in millions)			
Cash and Cash Equivalents	$ 234.1	$ 3.1	$ 4.2	$ 4.9
Restricted Cash	210.0	156.7	25.6	27.6
Total Cash, Cash Equivalents and Restricted Cash	$ 444.1	$ 159.8	$ 29.8	$ 32.5

2. NEW ACCOUNTING STANDARDS

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

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to the Registrants' business. The following standards will impact the financial statements.

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 sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, capital leases are known as finance leases going forward. Leases with terms of 12 months or longer are also subject to the new requirements. Fundamentally, the criteria used to determine lease classification remains the same, but is more subjective under the new standard.

New leasing standard implementation activities included the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements.

Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheets. Management elected 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.
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840.
Cumulative-effect adjustment in the period of adoption	Elect the optional transition practical expedient to adopt the new lease requirements through a cumulative-effect adjustment on the balance sheet in the period of adoption.

Management concluded that the result of adoption would not materially change the volume of contracts that qualify as leases going forward. The adoption of the new standard did not materially impact results of operations or cash flows, but did have a material impact on the balance sheets. See Note 12 - Leases for additional disclosures required by the new standard.

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

In June 2016, the FASB issued ASU 2016-13 requiring the recognition of an allowance for expected credit losses for financial instruments within its scope. Examples of financial instruments that are in scope include trade receivables, certain financial guarantees, and held-to-maturity debt securities. The allowance for expected credit losses should be based on historical information, current conditions and reasonable and supportable forecasts. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

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 continues to analyze the impact of this new standard. Implementation activities to date include the identification of the population of financial instruments within the AEP system that are subject to the new standard and evaluations to determine whether the new expected loss recognition model will cause any material changes to previously calculated allowance balances and supporting valuation models. Based on the assessments performed to date, Management does not expect the new standard to have a material impact on results of operations, financial position or cash flows.

Management's implementation activities, including an assessment of the new standard's disclosure requirements will continue throughout the fourth quarter of 2019. Management will continue to analyze the related impacts to allowances for credit losses and monitor for any potential industry implementation issues. Additionally, Management does not anticipate any significant changes to current accounting systems because of the adoption of the new standard. Management plans to adopt ASU 2016-13 and its related implementation guidance effective January 1, 2020.

3. COMPREHENSIVE INCOME

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

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional details.

AEP

Three Months Ended September 30, 2019	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of June 30, 2019	$ (127.2)	$ (15.9)	$ (87.6)	$ (230.7)
Change in Fair Value Recognized in AOCI	38.4	(0.8) (b)	—	37.6
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (a)	(0.1)	—	—	(0.1)
Purchased Electricity for Resale (a)	8.5	—	—	8.5
Amortization of Prior Service Cost (Credit)	—	—	(4.8)	(4.8)
Amortization of Actuarial (Gains) Losses	—	—	3.0	3.0
Reclassifications from AOCI, before Income Tax (Expense) Benefit	8.4	—	(1.8)	6.6
Income Tax (Expense) Benefit	1.8	—	(0.4)	1.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	6.6	—	(1.4)	5.2
Net Current Period Other Comprehensive Income (Loss)	45.0	(0.8)	(1.4)	42.8
Balance in AOCI as of September 30, 2019	$ (82.2)	$ (16.7)	$ (89.0)	$ (187.9)

Three Months Ended September 30, 2018	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of June 30, 2018	$ (30.4)	$ (15.3)	$ (49.1)	$ (94.8)
Change in Fair Value Recognized in AOCI	12.2	2.3	—	14.5
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (a)	(0.1)	—	—	(0.1)
Purchased Electricity for Resale (a)	(5.8)	—	—	(5.8)
Interest Expense (a)	—	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	—	(5.0)	(5.0)
Amortization of Actuarial (Gains) Losses	—	—	3.2	3.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(5.9)	0.4	(1.8)	(7.3)
Income Tax (Expense) Benefit	(1.3)	0.1	(0.4)	(1.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(4.6)	0.3	(1.4)	(5.7)
Net Current Period Other Comprehensive Income (Loss)	7.6	2.6	(1.4)	8.8
Balance in AOCI as of September 30, 2018	$ (22.8)	$ (12.7)	$ (50.5)	$ (86.0)

AEP

Nine Months Ended September 30, 2019	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ (84.8)	$ (120.4)
Change in Fair Value Recognized in AOCI	(92.3)	(4.5) (b)	—	(96.8)
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (a)	(0.1)	—	—	(0.1)
Purchased Electricity for Resale (a)	42.0	—	—	42.0
Interest Expense (a)	—	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	—	(14.3)	(14.3)
Amortization of Actuarial (Gains) Losses	—	—	9.0	9.0
Reclassifications from AOCI, before Income Tax (Expense) Benefit	41.9	0.5	(5.3)	37.1
Income Tax (Expense) Benefit	8.8	0.1	(1.1)	7.8
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	33.1	0.4	(4.2)	29.3
Net Current Period Other Comprehensive Income (Loss)	(59.2)	(4.1)	(4.2)	(67.5)
Balance in AOCI as of September 30, 2019	$ (82.2)	$ (16.7)	$ (89.0)	$ (187.9)

Nine Months Ended September 30, 2018	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Securities Available for Sale	Pension and OPEB	Total
			(in millions)		
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ (38.3)	$ (67.8)
Change in Fair Value Recognized in AOCI	30.4	2.3	—	—	32.7
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (a)	(0.1)	—	—	—	(0.1)
Purchased Electricity for Resale (a)	(23.6)	—	—	—	(23.6)
Interest Expense (a)	—	0.9	—	—	0.9
Amortization of Prior Service Cost (Credit)	—	—	—	(14.7)	(14.7)
Amortization of Actuarial (Gains) Losses	—	—	—	9.6	9.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(23.7)	0.9	—	(5.1)	(27.9)
Income Tax (Expense) Benefit	(5.0)	0.2	—	(1.1)	(5.9)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(18.7)	0.7	—	(4.0)	(22.0)
Net Current Period Other Comprehensive Income (Loss)	11.7	3.0	—	(4.0)	10.7
ASU 2018-02 Adoption	(6.1)	(2.7)	—	(8.2)	(17.0)
ASU 2016-01 Adoption	—	—	(11.9)	—	(11.9)
Balance in AOCI as of September 30, 2018	$ (22.8)	$ (12.7)	$ —	$ (50.5)	$ (86.0)

AEP Texas

Three Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2019	$ (3.9)	$ (10.6)	$ (14.5)
Change in Fair Value Recognized in AOCI	0.3	—	0.3
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—	—	—
Income Tax (Expense) Benefit	—	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—	—	—
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of September 30, 2019	$ (3.6)	$ (10.6)	$ (14.2)

Three Months Ended September 30, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2018	$ (4.9)	$ (9.8)	$ (14.7)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.4	—	0.4
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of September 30, 2018	$ (4.6)	$ (9.8)	$ (14.4)

Nine Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2018	$ (4.4)	$ (10.7)	$ (15.1)
Change in Fair Value Recognized in AOCI	0.3	—	0.3
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.6	—	0.6
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.6	0.1	0.7
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.5	0.1	0.6
Net Current Period Other Comprehensive Income (Loss)	0.8	0.1	0.9
Balance in AOCI as of September 30, 2019	$ (3.6)	$ (10.6)	$ (14.2)

Nine Months Ended September 30, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2017	$ (4.5)	$ (8.1)	$ (12.6)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.0	0.1	1.1
Income Tax (Expense) Benefit	0.2	—	0.2

Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.8	0.1	0.9
Net Current Period Other Comprehensive Income (Loss)	0.8	0.1	0.9
ASU 2018-02 Adoption	(0.9)	(1.8)	(2.7)
Balance in AOCI as of September 30, 2018	$ (4.6)	$ (9.8)	$ (14.4)

APCo

Three Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2019	$ 1.4	$ (8.1)	$ (6.7)
Change in Fair Value Recognized in AOCI	(0.3)	—	(0.3)
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	—	(1.4)	(1.4)
Amortization of Actuarial (Gains) Losses	—	0.6	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—	(0.8)	(0.8)
Income Tax (Expense) Benefit	—	(0.2)	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—	(0.6)	(0.6)
Net Current Period Other Comprehensive Income (Loss)	(0.3)	(0.6)	(0.9)
Balance in AOCI as of September 30, 2019	$ 1.1	$ (8.7)	$ (7.6)

Three Months Ended September 30, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2018	$ 2.3	$ (2.7)	$ (0.4)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	(0.4)	—	(0.4)
Amortization of Prior Service Cost (Credit)	—	(1.3)	(1.3)
Amortization of Actuarial (Gains) Losses	—	0.4	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.4)	(0.9)	(1.3)
Income Tax (Expense) Benefit	(0.1)	(0.2)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.3)	(0.7)	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(0.3)	(0.7)	(1.0)
Balance in AOCI as of September 30, 2018	$ 2.0	$ (3.4)	$ (1.4)

Nine Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2018	$ 1.8	$ (6.8)	$ (5.0)
Change in Fair Value Recognized in AOCI	(0.3)	—	(0.3)
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	(0.5)	—	(0.5)
Amortization of Prior Service Cost (Credit)	—	(4.0)	(4.0)
Amortization of Actuarial (Gains) Losses	—	1.6	1.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.5)	(2.4)	(2.9)
Income Tax (Expense) Benefit	(0.1)	(0.5)	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.4)	(1.9)	(2.3)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.9)	(2.6)
Balance in AOCI as of September 30, 2019	$ 1.1	$ (8.7)	$ (7.6)

Nine Months Ended September 30, 2018	Cash Flow Hedges		Pension and OPEB	Total
	Commodity	Interest Rate		
		(in millions)		
Balance in AOCI as of December 31, 2017	$ —	$ 2.2	$ (0.9)	$ 1.3
Change in Fair Value Recognized in AOCI	(0.7)	—	—	(0.7)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity for Resale (a)	0.9	—	—	0.9
Interest Expense (a)	—	(0.9)	—	(0.9)
Amortization of Prior Service Cost (Credit)	—	—	(3.9)	(3.9)

Amortization of Actuarial (Gains) Losses	—	—	1.0	1.0
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.9	(0.9)	(2.9)	(2.9)
Income Tax (Expense) Benefit	0.2	(0.2)	(0.6)	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.7	(0.7)	(2.3)	(2.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.7)	(2.3)	(3.0)
ASU 2018-02 Adoption	—	0.5	(0.2)	0.3
Balance in AOCI as of September 30, 2018	$ —	$ 2.0	$ (3.4)	$ (1.4)

I&M

Three Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2019	$ (10.7)	$ (2.4)	$ (13.1)
Change in Fair Value Recognized in AOCI	0.4	—	0.4
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—	—	—
Income Tax (Expense) Benefit	—	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—	—	—
Net Current Period Other Comprehensive Income (Loss)	0.4	—	0.4
Balance in AOCI as of September 30, 2019	$ (10.3)	$ (2.4)	$ (12.7)

Three Months Ended September 30, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2018	$ (12.2)	$ (1.7)	$ (13.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.4	—	0.4
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of September 30, 2018	$ (11.9)	$ (1.7)	$ (13.6)

Nine Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2018	$ (11.5)	$ (2.3)	$ (13.8)
Change in Fair Value Recognized in AOCI	0.4	—	0.4
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(0.6)	(0.6)
Amortization of Actuarial (Gains) Losses	—	0.5	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.0	(0.1)	0.9
Income Tax (Expense) Benefit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.8	(0.1)	0.7
Net Current Period Other Comprehensive Income (Loss)	1.2	(0.1)	1.1
Balance in AOCI as of September 30, 2019	$ (10.3)	$ (2.4)	$ (12.7)

Nine Months Ended September 30, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2017	$ (10.7)	$ (1.4)	$ (12.1)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	(0.6)	(0.6)
Amortization of Actuarial (Gains) Losses	—	0.6	0.6

Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.5	—	1.5
Income Tax (Expense) Benefit	0.3	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.2	—	1.2
ASU 2018-02 Adoption	(2.4)	(0.3)	(2.7)
Balance in AOCI as of September 30, 2018	$ (11.9)	$ (1.7)	$ (13.6)

OPCo

Three Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of June 30, 2019	$ 0.3
Change in Fair Value Recognized in AOCI	(0.2)
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.1)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.1)
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.1)
Net Current Period Other Comprehensive Income (Loss)	(0.3)
Balance in AOCI as of September 30, 2019	$ —

Three Months Ended September 30, 2018	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of June 30, 2018	$ 1.7
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.5)
Income Tax (Expense) Benefit	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.4)
Net Current Period Other Comprehensive Income (Loss)	(0.4)
Balance in AOCI as of September 30, 2018	$ 1.3

Nine Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2018	$ 1.0
Change in Fair Value Recognized in AOCI	(0.2)
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.0)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.0)
Income Tax (Expense) Benefit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
Balance in AOCI as of September 30, 2019	$ —

Nine Months Ended September 30, 2018	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 1.9
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
ASU 2018-02 Adoption	0.4
Balance in AOCI as of September 30, 2018	$ 1.3

PSO

Three Months Ended September 30, 2019		Cash Flow Hedge – Interest Rate
		(in millions)
Balance in AOCI as of June 30, 2019	$	1.6
Change in Fair Value Recognized in AOCI		(0.3)
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (a)		0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit		0.2
Income Tax (Expense) Benefit		0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		0.1
Net Current Period Other Comprehensive Income (Loss)		(0.2)
Balance in AOCI as of September 30, 2019	$	1.4

Three Months Ended September 30, 2018		Cash Flow Hedge – Interest Rate
		(in millions)
Balance in AOCI as of June 30, 2018	$	2.6
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (a)		(0.2)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(0.2)
Income Tax (Expense) Benefit		—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(0.2)
Net Current Period Other Comprehensive Income (Loss)		(0.2)
Balance in AOCI as of September 30, 2018	$	2.4

Nine Months Ended September 30, 2019		Cash Flow Hedge – Interest Rate
		(in millions)
Balance in AOCI as of December 31, 2018	$	2.1
Change in Fair Value Recognized in AOCI		(0.3)
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (a)		(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(0.5)
Income Tax (Expense) Benefit		(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(0.4)
Net Current Period Other Comprehensive Income (Loss)		(0.7)
Balance in AOCI as of September 30, 2019	$	1.4

Nine Months Ended September 30, 2018		Cash Flow Hedge – Interest Rate
		(in millions)
Balance in AOCI as of December 31, 2017	$	2.6
Change in Fair Value Recognized in AOCI		—
Amount of (Gain) Loss Reclassified from AOCI		
Interest Expense (a)		(0.9)
Reclassifications from AOCI, before Income Tax (Expense) Benefit		(0.9)
Income Tax (Expense) Benefit		(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		(0.7)
Net Current Period Other Comprehensive Income (Loss)		(0.7)
ASU 2018-02 Adoption		0.5
Balance in AOCI as of September 30, 2018	$	2.4

SWEPCo

Three Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2019	$ (2.5)	$ (2.7)	$ (5.2)
Change in Fair Value Recognized in AOCI	0.3	—	0.3
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—	(0.3)	(0.3)
Income Tax (Expense) Benefit	—	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—	(0.3)	(0.3)
Net Current Period Other Comprehensive Income (Loss)	0.3	(0.3)	—
Balance in AOCI as of September 30, 2019	$ (2.2)	$ (3.0)	$ (5.2)

Three Months Ended September 30, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2018	$ (6.4)	$ 1.7	$ (4.7)
Change in Fair Value Recognized in AOCI	2.3	—	2.3
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	(0.4)	0.1
Income Tax (Expense) Benefit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	(0.3)	0.1
Net Current Period Other Comprehensive Income (Loss)	2.7	(0.3)	2.4
Balance in AOCI as of September 30, 2018	$ (3.7)	$ 1.4	$ (2.3)

Nine Months Ended September 30, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (2.1)	$ (5.4)
Change in Fair Value Recognized in AOCI	0.3	—	0.3
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Amortization of Actuarial (Gains) Losses	—	0.4	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.0	(1.1)	(0.1)
Income Tax (Expense) Benefit	0.2	(0.2)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.8	(0.9)	(0.1)
Net Current Period Other Comprehensive Income (Loss)	1.1	(0.9)	0.2
Balance in AOCI as of September 30, 2019	$ (2.2)	$ (3.0)	$ (5.2)

Nine Months Ended September 30, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2017	$ (6.0)	$ 2.0	$ (4.0)
Change in Fair Value Recognized in AOCI	2.3	—	2.3
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (a)	1.6	—	1.6
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.6	(1.3)	0.3

Income Tax (Expense) Benefit	0.3	(0.3)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	(1.0)	0.3
Net Current Period Other Comprehensive Income (Loss)	3.6	(1.0)	2.6
ASU 2018-02 Adoption	(1.3)	0.4	(0.9)
Balance in AOCI as of September 30, 2018	$ (3.7)	$ 1.4	$ (2.3)

(a) Amounts reclassified to the referenced line item on the statements of income.
(b) The change in fair value includes $2 million and $6 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the three and nine months ended September 30, 2019, respectively. See "Sempra Renewables LLC" section of Note 14 for additional information.

4. RATE MATTERS

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

As discussed in the 2018 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2018 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2019 and updates the 2018 Annual Report.

Regulated Generating Unit to be Retired by 2020 (Applies to AEP and PSO)

In September 2018, management announced that the Oklaunion Power Station is probable of abandonment and is to be retired by October 2020. The table below summarizes the plant investment and cost of removal, currently being recovered, as well as the regulatory asset for accelerated depreciation for the generating unit as of September 30, 2019. See "2018 Oklahoma Base Rate Case" below for additional information.

Gross Investment	Accumulated Depreciation	Net Investment	Accelerated Depreciation Regulatory Asset (a)	Materials and Supplies	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
(dollars in millions)							
$ 106.6	$ 80.6	$ 26.0	$ 21.9	$ 3.2	$ 5.1	2020	27 years

(a) In October 2018, PSO changed depreciation rates to utilize the 2020 end-of-life and defer depreciation expense to a regulatory asset for the amount in excess of the previously OCC-approved depreciation rates for Oklaunion Power Station. See "2018 Oklahoma Base Rate Case" discussion below for additional information.

Regulatory Assets Pending Final Regulatory Approval (Applies to all Registrants except AEPTCo)

	AEP	
	September 30, 2019	December 31, 2018
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs – Unrecovered Plant	$ 50.3	$ 50.3
Kentucky Deferred Purchase Power Expenses	26.2	14.5
Oklaunion Power Station Accelerated Depreciation	21.9	5.5
Other Regulatory Assets Pending Final Regulatory Approval	5.4	9.3
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs	37.8	35.3
Storm-Related Costs (a)	—	152.4
Other Regulatory Assets Pending Final Regulatory Approval	26.8	20.7
Total Regulatory Assets Pending Final Regulatory Approval (b)	$ 168.4	$ 288.0

(a) In September 2019, AEP Texas securitized $235 million of storm-related costs. As a result of the securitization, the regulatory asset balance was transferred to Securitized Assets on the balance sheets. See "Texas Storm Cost Securitization" discussion below for additional information.
(b) In 2015, APCo recorded a $91 million reduction, before cost of removal of $17 million, to accumulated depreciation related to the remaining net book value of plants retired in 2015, primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. APCo's recovery of the remaining Virginia net book value for the retired plants will be considered in the Virginia SCC's 2020 triennial review of APCo's generation and distribution base rates.

Noncurrent Regulatory Assets	AEP Texas	
	September 30, 2019	December 31, 2018
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Rate Case Expense	$ 2.3	$ 0.2
Storm-Related Costs (a)	—	152.4
Total Regulatory Assets Pending Final Regulatory Approval	$ 2.3	$ 152.6

(a) In September 2019, AEP Texas securitized $235 million of storm-related costs. As a result of the securitization, the regulatory asset balance was transferred to Securitized Assets on the balance sheets. See "Texas Storm Cost Securitization" discussion below for additional information.

Noncurrent Regulatory Assets	APCo	
	September 30, 2019	December 31, 2018
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs – Materials and Supplies	$ 5.1	$ 9.0
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs	37.8	35.3
Other Regulatory Assets Pending Final Regulatory Approval	—	0.6
Total Regulatory Assets Pending Final Regulatory Approval (a)	$ 42.9	$ 44.9

(a) In 2015, APCo recorded a $91 million reduction, before cost of removal of $17 million, to accumulated depreciation related to the remaining net book value of plants retired in 2015, primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. APCo's recovery of the remaining Virginia net book value for the retired plants will be considered in the Virginia SCC's 2020 triennial review of APCo's generation and distribution base rates.

Noncurrent Regulatory Assets	I&M	
	September 30, 2019	December 31, 2018
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Cook Plant Study Costs	$ 10.7	$ —
Other Regulatory Assets Pending Final Regulatory Approval	0.1	3.3
Total Regulatory Assets Pending Final Regulatory Approval	$ 10.8	$ 3.3

Noncurrent Regulatory Assets	OPCo	
	September 30, 2019	December 31, 2018
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.1	$ 1.0
Total Regulatory Assets Pending Final Regulatory Approval	$ 0.1	$ 1.0

Noncurrent Regulatory Assets	PSO	
	September 30, 2019	December 31, 2018
	(in millions)	
Regulatory Assets Currently Earning a Return		
Oklaunion Power Station Accelerated Depreciation	$ 21.9	$ 5.5
Regulatory Assets Currently Not Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	—	0.5
Total Regulatory Assets Pending Final Regulatory Approval	$ 21.9	$ 6.0

Noncurrent Regulatory Assets	SWEPCo	
	September 30, 2019	December 31, 2018
	(in millions)	
Regulatory Assets Currently Earning a Return		
Plant Retirement Costs – Unrecovered Plant	$ 50.3	$ 50.3
Other Regulatory Assets Pending Final Regulatory Approval	0.3	0.3
Regulatory Assets Currently Not Earning a Return		
Asset Retirement Obligation - Arkansas, Louisiana	6.8	5.3
Rate Case Expense – Texas	1.4	4.9
Other Regulatory Assets Pending Final Regulatory Approval	4.2	3.6
Total Regulatory Assets Pending Final Regulatory Approval	$ 63.0	$ 64.4

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

AEP Texas Rate Matters (Applies to AEP and AEP Texas)

AEP Texas Interim Transmission and Distribution Rates

As of September 30, 2019, AEP Texas' cumulative revenues from interim transmission and distribution rate increases from 2008 through 2019, subject to review, are estimated to be $1.3 billion. The 2019 base rate case described below could result in a refund to customers if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition.

2019 Texas Base Rate Case

In May 2019, AEP Texas filed a request with the PUCT for a $56 million annual increase in rates based upon a proposed 10.5% return on common equity. The filing includes a proposed Income Tax Refund Rider that will refund $21 million annually of Excess ADIT that is primarily not subject to rate normalization requirements. The rate case also seeks a prudence determination on all capital additions included in interim rates from 2008.

In July and August 2019, PUCT staff and various intervenors filed testimony. The PUCT staff recommended a $63 million annual rate reduction based on a 9.35% return on common equity while intervenors recommended annual rate reductions of up to $159 million based on a return on common equity ranging from 9% to 9.2%. The difference between AEP Texas' requested annual base rate increase and the PUCT staff's and various intervenor's recommendations are primarily due to: (a) recommended capital structure of 60% debt and 40% common equity as compared to the 55% debt and 45% common equity requested by AEP Texas, (b) a reduction in the requested return on common equity and (c) various disallowances that could potentially result in write-offs exceeding $450 million. The PUCT staff's recommended disallowances primarily consisted of $85 million in capital incentives and $26 million for capitalized vegetation management expenses. The intervenors recommended disallowances primarily consisted of (a) $173 million

for a newly constructed transmission operations center and other service centers, (b) $94 million for Hurricane Harvey costs, (c) $36 million for capitalized cross arms and (d) $21 million for capitalized plant costs related to unreimbursed damages to assets caused by third-parties. In addition, one intervenor recommended AEP Texas refund $115 million of Excess ADIT, which includes $2 million in interest, related to previously owned deregulated generation assets. AEP Texas recorded $113 million as a favorable adjustment to income tax expense in 2017 as a result of Tax Reform. Hearings were held in August 2019 and briefs were filed in September 2019. AEP Texas is expecting a Proposal for Decision from the ALJ in the fourth quarter of 2019. The PUCT is expected to issue an order on the case by the first quarter of 2020. If any of these costs are not recoverable or refunds of revenues collected under interim transmission and distribution rates are ordered to be returned to customers, it could reduce future net income and cash flows and impact financial condition.

Texas Storm Cost Securitization

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. In March 2019, AEP Texas filed a request to securitize total estimated distribution-related system restoration costs with the PUCT, which included estimated carrying costs. In June 2019, the PUCT approved the financing order. As part of the financing order, AEP Texas agreed to offset $64 million of Excess ADIT that is not subject to rate normalization requirements against the total distribution-related system restoration costs. In September 2019, AEP Texas issued $235 million of securitization bonds. The securitization bonds included carrying costs of $33 million, which includes $21 million of debt carrying costs recorded as a reduction to Interest Expense in 2019.

The remaining $95 million of estimated net transmission-related system restoration costs, including carrying charges, is expected to be recovered in the 2019 Texas Base Rate Case described above or through interim transmission base rate increases. If these costs are not recovered, it could have an adverse effect on future net income, cash flows and financial condition.

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

Virginia Legislation Affecting Earnings Reviews

Under a 2015 amended Virginia law, APCo’s existing generation and distribution base rates were frozen until after the Virginia SCC ruled on APCo’s next biennial review. The 2015 amendments also precluded the Virginia SCC from performing biennial reviews of APCo’s earnings for the years 2014 through 2017.

New Virginia legislation impacting investor-owned utilities was enacted, effective July 1, 2018, that requires APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 earnings test years (triennial review). Triennial reviews are subject to an earnings test which provides that 70% of any earnings exceeding 70 basis points over the Virginia SCC authorized return on common equity would be refunded to customers or be used to lower APCo’s Virginia retail base rates on a prospective basis. The Virginia legislation also states that, under certain circumstances, costs associated with asset impairments related to early retirement determinations made by a utility for generation facilities fueled by coal, natural gas or oil or for automated meters be considered fully recovered in the period recorded.

In November 2018, the Virginia SCC approved a return on common equity of 9.42% applicable to APCo base rate earnings for the 2017-2019 triennial period and rate adjustment clauses from November 2018 through November 2020. Management has reviewed APCo’s actual and forecasted earnings for the triennial period and concluded that it is not probable, but is reasonably possible, that APCo will over-earn in Virginia during the 2017-2019 triennial period. Due to various uncertainties, including weather, storm restoration, weather-normalized demand and potential customer shopping during 2019, management cannot estimate a range of potential APCo Virginia over-earnings during the 2017-2019 triennial period. If the Virginia triennial review of APCo earnings results in any disallowance, it could reduce future net income and cash flows and impact financial condition.

Virginia Staff Depreciation Study Request

In November 2018, Virginia staff recommended that APCo implement new Virginia jurisdictional depreciation rates effective January 1, 2018 based on APCo's depreciation study that was prepared at Virginia staff's request using December 31, 2017 APCo property balances. Implementation of those depreciation rates would result in a $21 million pretax increase in annual depreciation expense ($6 million related to transmission) with no corresponding increase in retail base rates. In December 2018, APCo submitted a response to the Virginia staff stating that it was inappropriate for APCo to change Virginia depreciation rates in advance of the Virginia SCC's upcoming Triennial Review of APCo, citing the Virginia SCC's November 2014 order to not change APCo's Virginia depreciation rates until APCo's next base rate case/review. If the Virginia SCC were to issue an order approving the Virginia staff's recommended retroactive change in APCo's Virginia depreciation rates, it would reduce future net income and cash flows and impact financial condition.

Virginia Tax Reform

In March 2019, the Virginia SCC issued an order to reduce APCo's base rates to refund: (a) $40 million annually for ongoing annual tax savings, (b) $9 million annually of Excess ADIT associated with certain depreciable property using ARAM, (c) $94 million of Excess ADIT that is not subject to rate normalization requirements over three years and (d) a one-time credit of $22 million for estimated excess taxes collected from customers during the 15-month period ending March 31, 2019.

2018 West Virginia Base Rate Case

In May 2018, APCo and WPCo filed a joint request with the WVPSC to increase their combined West Virginia base rates by $115 million ($98 million related to APCo) annually based on a 10.22% return on common equity. The proposed annual increase included $32 million ($28 million related to APCo) due to increased annual depreciation expense and reflected the impact of the reduction in the federal income tax rate due to Tax Reform. In October 2018, APCo and WPCo filed updated schedules supporting a $95 million ($80 million related to APCo) annual increase in West Virginia base rates primarily due to the impact of West Virginia Tax Reform.

In February 2019, the WVPSC issued an order approving a Stipulation and Settlement agreement between APCo, WPCo, WVPSC staff and certain intervenors. The agreement included an annual base rate increase of $44 million ($36 million related to APCo) based upon a 9.75% return on common equity effective March 2019. The agreement also included: (a) $18 million ($14 million related to APCo) of increased annual depreciation expense, (b) a $24 million refund ($19 million related to APCo) over two years, through a rider beginning March 2019, of Excess ADIT that is not subject to rate normalization requirements, (c) the utilization of $14 million ($12 million related to APCo) of Excess ADIT that is not subject to rate normalization requirements to offset regulatory asset balances relating to ENEC, (d) an agreement to seek WVPSC approval of economic incentive programs to provide funds to aid in industrial and commercial development and (e) an agreement, barring any unforeseen events, to not initiate another base rate proceeding prior to April 1, 2020.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP 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. Through September 30, 2019, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $987 million. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

In 2018, the PUCT adopted a rule requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for rate proceedings. The rule requires ETT to file for a comprehensive rate review no later than February 1, 2021.

<u>I&M Rate Matters</u> (Applies to AEP and I&M)

Michigan Tax Reform

In October 2018, I&M made a filing with the MPSC recommending to: (a) refund approximately $68 million of Excess ADIT associated with certain depreciable property using ARAM and (b) refund approximately $37 million of Excess ADIT that is not subject to rate normalization requirements over ten years. In September 2019, an ALJ issued a Proposal for Decision and various intervenors filed objections which included changing the refund period from ten years to seven years. In October 2019, I&M filed responses to the various intervenor objections. An order from the MPSC regarding Excess ADIT is expected in the fourth quarter of 2019.

2019 Indiana Base Rate Case

In May 2019, I&M filed a request with the IURC for a $172 million annual increase. The requested increase in Indiana rates would be phased in through January 2021 and is based upon a proposed 10.5% return on common equity. The proposed annual increase includes $78 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense includes $52 million related to proposed investments and $26 million related to increased depreciation rates. The request includes the continuation of all existing riders and a new Automated Metering Infrastructure rider for proposed meter projects.

In August 2019, various intervenors filed testimony that recommended annual rate increases ranging from $2 million to $33 million based upon a return on common equity ranging from 9% to 9.73%. The difference between I&M's requested annual base rate increase and the intervenor's recommendations are primarily due to: (a) proposed denial of return on and of certain new plant investments, (b) proposed lower depreciation rates, (c) a reduction in the requested return on common equity and (d) exclusion of I&M's proposed re-allocation of capacity costs related to I&M's June 2020 loss of a significant FERC wholesale contract. In addition, certain parties recommended disallowances that could potentially result in write-offs of $41 million related to the remaining book value of existing Indiana jurisdictional meters and $11 million associated with certain Cook Plant study costs.

In September 2019, I&M filed testimony rebutting the various parties' recommendations. A hearing at the IURC began in October 2019. The IURC is expected to issue an order on the case by the first quarter of 2020. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2019 Michigan Base Rate Case

In June 2019, I&M filed a request with the MPSC for a $58 million annual increase. The requested increase in Michigan rates would be phased in through June 2020 and is based upon a proposed 10.5% return on common equity. The proposed annual increase includes $19 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense includes $13 million related to proposed investments and $6 million related to increased depreciation rates. The proposed annual increase also includes $10 million for annual lost revenue related to the Michigan Electric Customer Choice Program that began in 2019.

In October 2019, MPSC staff and various intervenors filed testimony. The MPSC staff recommended a $38 million annual rate increase based upon a 9.75% return on common equity while intervenors recommended annual rate increases of up to $28 million based on a return on common equity ranging from 9.1% to 9.25%. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

Ohio ESP Filings

ESP Extension through 2024

In 2016, OPCo refiled its amended ESP extension application and supporting testimony, consistent with the terms of the modified and approved stipulation agreement and based upon a 2016 PUCO order. The amended filing proposed to extend the ESP through May 2024.

In April 2018, the PUCO issued an order approving the ESP extension stipulation agreement, with no significant changes. In October 2018, an intervenor filed an appeal with the Ohio Supreme Court challenging various approved riders. In October 2019, oral arguments were held in the Ohio Supreme Court. If the Ohio Supreme Court reverses the PUCO's decision, it could reduce future net income and cash flows and impact financial condition.

OPCo's Enhanced Service Reliability Rider (ESRR) authorized under the ESP is subject to annual audits. In May 2018, the PUCO staff filed comments indicating that 2016 spending under the ESRR was subject to authorized limits and that OPCo overspent those limits. OPCo filed reply comments objecting to the PUCO staff's position, including the method of calculating the overspent amount. In March 2019, the PUCO staff filed additional comments which adjusted the method of the calculation but maintained that OPCo overspent the authorized limit in 2016 and 2017, which could result in a refund of $10 million. Management believes that both 2016 and 2017 ESRR spending is not subject to an authorized limit and that a spending limit was not established until 2018, as part of the ESP extension. A hearing was held in May 2019 to address the 2016 audit. Post-hearing briefs in this case were filed in June 2019 and reply briefs were filed in July 2019. If it is determined OPCo did have an authorized spending limit under the ESRR in 2016 and 2017, and refunds are ordered, it would reduce future net income and cash flows and impact financial condition.

2016 SEET Filing

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 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.

In 2016, OPCo recorded a 2016 SEET provision of $58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement that was filed at the PUCO in December 2016 and subsequently approved in February 2017: (a) gain on the deferral of RSR costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings.

In February 2019, the PUCO issued an order that OPCo did not have significantly excessive earnings in 2016. As a result of the order, OPCo reversed the $58 million provision in the first quarter of 2019.

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

2018 Oklahoma Base Rate Case

In 2018, PSO filed a request with the OCC for an $88 million annual increase in Oklahoma retail rates based upon a 10.3% return on common equity. PSO also proposed to implement a performance-based rate plan that combines a formula rate with a set of customer-focused performance incentive measures related to reliability, public safety, customer satisfaction and economic development. The proposed annual increase included $13 million related to increased annual depreciation rates and $7 million related to increased storm expense amortization. The requested increase in annual depreciation rates included the recovery of Oklaunion Power Station through 2028 (currently being recovered in rates through 2046). Management has announced plans to retire Oklaunion Power Station by October 2020.

In March 2019, the OCC issued an order approving a Stipulation and Settlement agreement for a $46 million annual increase, based on a 9.4% return on equity effective with the first billing cycle of April 2019. The order also included agreements between the parties that: (a) depreciation rates will remain unchanged, (b) PSO will file a new base rate request no earlier than October 2020 and no later than October 2021 and (c) PSO will refund Excess ADIT that is not subject to rate normalization requirements over five years instead of the ten years ordered in the Oklahoma Tax Reform case. The order did not approve the performance-based rate plan but instead provided for an expansion of the SPP Transmission Tariff that tracks previously untracked SPP costs and a new Distribution Reliability and Safety Rider that provides additional revenues capped at $5 million per year for distribution projects related to safety and reliability that are not normal distribution replacements.

SWEPCo Rate Matters (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.

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, SWEPCo reversed $114 million of a previously recorded regulatory disallowance in 2013. The resulting annual base rate increase was approximately $52 million. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In August 2018, SWEPCo filed a Motion for Reconsideration at the Court of Appeals, which was denied. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. In May 2019, various intervenors filed replies to the petition. In July 2019, SWEPCo filed its response to these replies. The Texas Supreme Court has requested full briefing by the parties. SWEPCo's initial brief is due in October 2019. Response briefs are due in November 2019 and SWEPCo's reply brief is due in December 2019.

As of September 30, 2019, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If certain parts of the PUCT order are overturned and if SWEPCo cannot ultimately fully recover its approximate 33% 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 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in- service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million in additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

As a result of the final order, in 2017 SWEPCo: (a) recorded an impairment charge of $19 million, which included $7 million associated with the lack of return on Welsh Plant, Unit 2 and $12 million related to other disallowed plant investments, (b) recognized $32 million of additional revenues, for the period of May 2017 through December 2017, that was surcharged to customers in 2018 and (c) recognized an additional $7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEPCo implemented new rates in February 2018 billings. The $32 million of additional 2017 revenues was collected during 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors. If certain parts of the PUCT order are overturned, it could reduce future net income and cash flows and impact financial condition.

2018 Louisiana Formula Rate Filing

In April 2018, SWEPCo filed its formula rate plan for test year 2017 with the LPSC. The filing included a net $28 million annual increase, which was effective August 2018 and included SWEPCo's Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls. The filing also included a reduction in the federal income tax rate due to Tax Reform but did not address the return of Excess ADIT benefits to customers.

In July 2018, SWEPCo made a supplemental filing to its formula rate plan with the LPSC to reduce the requested annual increase to $18 million. The difference between SWEPCo's requested $28 million annual increase and the $18 million annual increase in the supplemental filing is primarily the result of the return of Excess ADIT benefits to customers.

In October 2018, the LPSC staff issued a recommendation that SWEPCo refund $11 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through July 31, 2018. In June 2019, the LPSC staff issued its report which reaffirmed its $11 million refund recommendation. The report also contends that SWEPCo's requested annual rate increase of $18 million, which was implemented in August 2018, is overstated by $4 million and proposes an annual rate increase of $14 million. Additionally, the report recommends SWEPCo refund the excess over-collections associated with the $4 million difference for the period of August 2018 through the implementation of new rates. In July 2019, the LPSC approved the $11 million refund. A decision by the LPSC on the remaining issues is expected in the fourth quarter of 2019.

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 total approximately $550 million, excluding AFUDC. As of September 30, 2019, SWEPCo had incurred costs of $399 million, including AFUDC, related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of September 30, 2019, the total net book value of Welsh Plant, Units 1 and 3 was $612 million, before cost of removal, including materials and supplies inventory and CWIP.

In 2016, as approved by the APSC, SWEPCo began recovering $79 million related to the Arkansas jurisdictional share of these environmental costs, subject to prudence review in the next Arkansas filed base rate proceeding. In 2017, the LPSC approved recovery of $131 million in investments related to its Louisiana jurisdictional share of environmental controls installed at Welsh Plant. SWEPCo's approved Louisiana jurisdictional share of Welsh Plant deferrals: (a) are $10 million, excluding $5 million of unrecognized equity as of September 30, 2019, (b) is subject to review by the LPSC and (c) includes a weighted average cost of capital return on environmental investments and the related depreciation expense and taxes. See "2018 Louisiana Formula Rate Filing" and "2019 Arkansas Base Rate Case" disclosures for additional information.

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

2019 Arkansas Base Rate Case

In February 2019, SWEPCo filed a request with the APSC for a $75 million increase in Arkansas base rates based upon a proposed 10.5% return on common equity. The filing requests rate base treatment for the Stall Plant and environmental retrofits that are currently being recovered through riders. Eliminating these riders would result in a net annual requested base rate increase of $58 million. The proposed net annual increase includes $12 million related to vegetation management to improve the reliability of its Arkansas distribution system. The filing also provides notice of SWEPCo's proposal to have its rates regulated under the formula rate review mechanism authorized by Arkansas law, including a Formula Rate Review Rider. In October 2019, SWEPCo reduced its requested base rate increase from $75 million to $67 million.

In October 2019, SWEPCo, the APSC staff and various intervenors filed a unanimous stipulation and settlement agreement with the APSC. The agreement includes a proposed annual base rate increase of $53 million ($24 million net of amounts currently recovered through riders) based upon a 9.45% return on common equity and includes $6 million for increased annual depreciation expense. The agreement provides recovery for: (a) the Stall Plant, (b) environmental retrofit projects and (c) the remaining net book value, with a debt return for investors, of Welsh Unit 2. The agreement also includes a proposal to have its rates regulated under the formula rate mechanism authorized by Arkansas law, including a Formula Rate Review Rider. Also in October 2019, a settlement hearing with the APSC was held. SWEPCo expects the APSC to issue an order in the fourth quarter of 2019. If any of these costs are not recoverable, or disallowances were to occur, it could reduce future net income and cash flows and impact financial condition.

FERC Rate Matters

FERC Transmission Complaint - AEP's PJM Participants (Applies to AEP, AEPTCo, APCo, I&M and OPCo)

In 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM 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 March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). The settlement agreement: (a) established a base ROE for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) required AEP's transmission owning subsidiaries within PJM to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter of 2018 and (c) increased the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the Excess ADIT that is not subject to rate normalization requirements over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In May 2019, the FERC approved the settlement agreement.

FERC Transmission Complaint - AEP's SPP Participants (Applies to AEP, AEPTCo, PSO and SWEPCo)

In 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint through September 5, 2018. In September 2018, the same parties filed another complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.71%, effective upon the date of the second complaint. In June 2019, the FERC approved an unopposed settlement agreement between AEP's transmission owning subsidiaries within SPP and the complainants. The settlement agreement established a base ROE of 10% (10.50% inclusive of the RTO incentive adder of 0.5%) effective January 1, 2019. Additionally, refunds including carrying charges will be made from the date of the first complaint through December 31, 2018. Refunds for the period prior to 2019 will be made at the time of the 2019 true-up of 2018 rates. Refunds from January 2019 onward will conclude with the 2020 true-up of 2019 rates.

Modifications to AEP's SPP Transmission Rates (Applies to AEP, AEPTCo, PSO and SWEPCo)

In 2017, AEP's transmission owning subsidiaries within SPP filed an application at the FERC to modify the SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected calendar year financial activity and projected plant balances. The FERC accepted the proposed modifications effective January 1, 2018, subject to refund. In February 2019, AEP's transmission owning subsidiaries within SPP filed an uncontested settlement agreement with the FERC resolving all outstanding issues. In June 2019, the FERC approved the settlement agreement.

5. 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. The Commitments, Guarantees and Contingencies note within the 2018 Annual Report should be read in conjunction with this report.

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, AEP Texas 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 a $4 billion revolving credit facility due in June 2022, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of September 30, 2019, no letters of credit were issued under the 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 issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $405 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2019 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 204.4	October 2019 to October 2020
AEP Texas	2.2	July 2020
OPCo	3.6	April 2020 to September 2020

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 $155 million. Since SWEPCo uses self-bonding, the guarantee commits SWEPCo to complete the reclamation, in the event, Sabine does not complete the work. This guarantee ends upon depletion of reserves and completion of reclamation. The reserves are estimated to deplete in 2036 with reclamation completed by 2046 at an estimated cost of $107 million. Actual reclamation costs could vary due to inflation and scope changes to the mine reclamation. As of September 30, 2019, SWEPCo has collected $77 million through a rider for reclamation costs, of which $83 million was recorded in Asset Retirement Obligations, offset by $6 million recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

Sabine charges all of its costs to its only customer, SWEPCo, which recovers these costs through its fuel clauses.

Guarantees of Equity Method Investees (Applies to AEP)

In December 2016, 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 September 30, 2019, the maximum potential amount of future payments associated with this guarantee was $75 million, which expired in October 2019.

In April 2019, AEP acquired Sempra Renewables LLC. See "Acquisitions" section of Note 6 for additional information.

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 September 30, 2019, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase-and-sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf. AEPSC also conducts power purchase-and-sale activity on behalf of PSO and SWEPCo, who are jointly and severally liable for activity conducted on their behalf.

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

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 non-hazardous materials. The Registrants currently incur costs to dispose of these substances safely. For remediation processes not specifically discussed, management does not anticipate that the liabilities, if any, arising from such remediation processes would have a material effect on the financial statements.

NUCLEAR CONTINGENCIES (Applies to AEP and I&M)

I&M owns and operates the Cook Plant under licenses granted by the Nuclear Regulatory Commission. 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.

OPERATIONAL CONTINGENCIES

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

In 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would 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, refueling or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

AEGCo and I&M sought and were granted dismissal by the U.S. District Court for the Southern District of Ohio of certain of the plaintiffs' claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. Plaintiffs voluntarily dismissed the surviving claims that AEGCo and I&M failed to exercise prudent utility practices with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit.

In 2017, the U.S. Court of Appeals for the Sixth Circuit issued an opinion and judgment affirming the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims, reversing the district court's dismissal of the breach of contract claims and remanding the case for further proceedings.

Thereafter, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree. The district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. The consent decree was modified based on an agreement among the parties in July 2019. As part of the modification to the consent decree, I&M agreed to provide an additional $7.5 million to citizens' groups and the states for environmental mitigation projects. As joint owners in the Rockport Plant, the $7.5 million payment was shared between AEGCo and I&M based on the joint ownership agreement. See "Modification of the New Source Review Litigation Consent Decree" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management cannot determine a range of potential losses that are reasonably possible of occurring.

Patent Infringement Complaint

In July 2019, Midwest Energy Emissions Corporation and MES Inc. (collectively, the plaintiffs) filed a patent infringement complaint against various parties, including AEP Texas, AGR, Cardinal Operating Company and SWEPCo (collectively, the AEP Defendants). The complaint alleges that the AEP Defendants infringed two patents owned by the plaintiffs by using specific processes for mercury control at certain coal-fired generating stations. The complaint seeks injunctive relief and damages. Management will continue to defend against the claims. Management is unable to determine a range of potential loss that is reasonably possible of occurring.

6. ACQUISITIONS AND IMPAIRMENTS

The disclosures in this note apply to AEP only unless indicated otherwise.

ACQUISITIONS

Sempra Renewables LLC (Generation & Marketing Segment)

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation and battery assets valued at approximately $1.1 billion. This acquisition is part of AEP's strategy to grow its renewable generation portfolio and to diversify generation resources. AEP paid $583 million in cash and acquired a 50% ownership interest in five non-consolidated joint ventures with net assets valued at $406 million as of the acquisition date (which includes $364 million of existing debt obligations). Additionally, the transaction included the acquisition of two tax equity partnerships and the associated recognition of noncontrolling tax equity interest of $135 million. The purchase price, subject to working capital adjustments, was allocated as follows:

Purchase Price Allocation of Sempra Renewables LLC at Acquisition Date - April 22nd, 2019

Assets:			**Liabilities and Equity:**			**Net Purchase Price**	
			(in millions)				
Current Assets	$	9.7	Current Liabilities	$	12.9		
Property, Plant and Equipment		238.1	Asset Retirement Obligations		5.7		
Investment in Joint Ventures		405.9	**Total Liabilities**		18.6		
Other Noncurrent Assets		82.9	Noncontrolling Interest		134.8		
Total Assets	$	736.6	**Liabilities and Noncontrolling Interest**	$	153.4	$	583.2

Management allocated the purchase price based upon the relative fair value of the assets acquired and noncontrolling interests assumed. The fair value of the primary assets acquired and the noncontrolling interests assumed was determined using a discounted cash flow method under the income approach. The key input assumptions utilized in the determination of the fair value of these assets were the pricing and terms of the existing purchase power agreements, forecasted market power prices, forecasted PTCs from the wind farms, expected wind farm net capacity, forecasted cash benefits from income tax depreciation and discount rates reflecting risk inherent in the future cash flows and future power prices. Additional key input assumptions for the fair value of the noncontrolling interests include the terms of the limited liability company agreements that dictate the sharing of the tax attributes and cash flows associated with the tax equity partnerships. Under the accounting rules for acquisitions, AEP has one year to finalize the purchase price allocation, including working capital adjustments and other closing adjustments.

Upon closing of the purchase, Sempra Renewables LLC was legally renamed AEP Wind Holdings LLC. AEP Wind Holdings LLC develops, owns and operates, or holds interests in, wind generation facilities in the United States. The operating wind generation portfolio includes seven wind farms. Five wind farms are jointly-owned with BP Wind Energy, and two wind farms are consolidated by AEP and are tax equity partnerships with nonaffiliated noncontrolling interests. All seven wind farms have long-term PPAs for 100% of their energy production. One of the joint venture wind farms has PPAs with I&M and OPCo for a portion of its energy production which totaled $2 million and $3 million, respectively, of purchased electricity for the three months ended September 30, 2019, and $5 million and $10 million, respectively, for the nine months ended September 30, 2019. Another joint venture wind farm has a PPA with SWEPCo for a portion of its energy production which totaled $3 million and $6 million of purchased electricity for the three and nine months ended September 30, 2019, respectively. The PPAs with I&M, OPCo and SWEPCo were executed prior to the acquisition of the wind farms and will be accounted for in accordance with the accounting guidance for "Related Parties."

Parent has issued guarantees over the performance of the joint ventures. If a joint venture were to default on payments or performance, Parent would be required to make payments on behalf of the joint venture. As of September 30, 2019, the maximum potential amount of future payments associated with these guarantees was $186 million, with the last guarantee expiring in December 2037. The liability recorded associated with these guarantees was $34 million as of September 30, 2019.

The acquired business contributed revenues and Net Income to AEP that were not material for the period April 22, 2019 to September 30, 2019. The pro-forma revenue and net income related to the acquisition of Sempra Renewables LLC were not material for the three and nine months ended September 30, 2019 and 2018.

See Note 14 - Variable Interest Entities and Equity Method Investments for additional information related to the purchased wind farms.

Santa Rita East (Generation & Marketing Segment)

In July 2019, AEP acquired a 75% interest, or 227 MWs, in Santa Rita East for approximately $356 million. In accordance with the accounting guidance for “Business Combinations,” management determined that the acquisition of Santa Rita East represents an asset acquisition. Additionally, and in accordance with the accounting guidance for “Consolidation,” management concluded that Santa Rita East is a VIE. As a result, to account for the initial consolidation of Santa Rita East, management applied the acquisition method by allocating the purchase price based on the relative fair value of the assets acquired and noncontrolling interest assumed. The fair value of the primary assets acquired and the noncontrolling interest assumed was determined using the market approach. The key input assumptions were the transaction price paid for AEP’s interest in Santa Rita East and recent third-party market transactions for similar wind farms. See “Santa Rita East” section of Note 14 for additional information.

IMPAIRMENTS

Other Assets (Corporate and Other) (Vertically Integrated Utilities Segment) (Applies to AEP and APCo)

In the first quarter of 2018, AEP was notified by an equity investee that it had ceased operations. AEP recorded a pretax impairment of $21 million in Other Operation on the statements of income related to the equity investment and related assets. The impairment also had an immaterial impact to APCo.

Merchant Generating Assets (Generation & Marketing Segment)

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017. As of September 30, 2018, the Racine reconstruction project had accumulated new capital expenditures of $35 million. Due to a significant increase in estimated costs to complete the reconstruction project, in the third quarter of 2018, an impairment analysis was performed. AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful life of Racine based upon energy and capacity price curves, which were developed internally with observable Level 2 third-party quotations and unobservable Level 3 inputs, as well as management’s forecasts of operating expenses and capital expenditures. AEP performed step two of the impairment analysis on Racine using a ten-year discounted cash flow model based upon similar forecasted information used in the step one test. The step two analysis resulted in a determination that the fair value of Racine in its condition as of September 30, 2018 was $0. As a result, AEP recorded a pretax impairment of $35 million in Other Operation on the statements of income in the third quarter of 2018. In October 2018, AEP received authorization from the FERC to restart generation at Racine and generation resumed in November 2018.

Due to weather-related delays in the first quarter of 2019, reconstruction activities at Racine are now estimated to be completed in the first half of 2020. AEP expects to incur additional capital expenditures to complete the reconstruction project, at which point the fair value of Racine, as fully operational, is expected to approximate the book value once complete. Future revisions in cost estimates or delays in completion could result in additional losses which could reduce future net income and cash flows and impact financial condition.

7. BENEFIT PLANS

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

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.

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		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 23.8	$ 24.4	$ 2.4	$ 2.9
Interest Cost	51.1	46.9	12.6	11.8
Expected Return on Plan Assets	(74.0)	(72.6)	(23.4)	(25.6)
Amortization of Prior Service Credit	—	—	(17.3)	(17.3)
Amortization of Net Actuarial Loss	14.4	21.3	5.5	2.7
Net Periodic Benefit Cost (Credit)	$ 15.3	$ 20.0	$ (20.2)	$ (25.5)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 71.6	$ 73.2	$ 7.1	$ 8.7
Interest Cost	153.3	140.8	37.9	35.5
Expected Return on Plan Assets	(222.0)	(217.7)	(70.3)	(76.7)
Amortization of Prior Service Credit	—	—	(51.8)	(51.8)
Amortization of Net Actuarial Loss	43.2	63.9	16.6	7.9
Net Periodic Benefit Cost (Credit)	$ 46.1	$ 60.2	$ (60.5)	$ (76.4)

AEP Texas

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 2.2	$ 2.3	$ 0.1	$ 0.3
Interest Cost	4.4	4.0	1.0	0.9
Expected Return on Plan Assets	(6.5)	(6.4)	(1.9)	(2.1)
Amortization of Prior Service Credit	—	—	(1.5)	(1.5)
Amortization of Net Actuarial Loss	1.2	1.8	0.5	0.2
Net Periodic Benefit Cost (Credit)	$ 1.3	$ 1.7	$ (1.8)	$ (2.2)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 6.5	$ 6.9	$ 0.5	$ 0.7
Interest Cost	13.1	12.0	3.0	2.8
Expected Return on Plan Assets	(19.4)	(19.2)	(5.8)	(6.4)
Amortization of Prior Service Credit	—	—	(4.4)	(4.4)
Amortization of Net Actuarial Loss	3.7	5.4	1.4	0.6
Net Periodic Benefit Cost (Credit)	$ 3.9	$ 5.1	$ (5.3)	$ (6.7)

APCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 2.4	$ 2.4	$ 0.2	$ 0.3
Interest Cost	6.3	5.8	2.2	2.1
Expected Return on Plan Assets	(9.4)	(9.1)	(3.7)	(4.0)
Amortization of Prior Service Credit	—	—	(2.5)	(2.5)
Amortization of Net Actuarial Loss	1.8	2.6	1.0	0.4
Net Periodic Benefit Cost (Credit)	$ 1.1	$ 1.7	$ (2.8)	$ (3.7)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 7.1	$ 7.0	$ 0.7	$ 0.8
Interest Cost	18.9	17.6	6.5	6.2
Expected Return on Plan Assets	(28.1)	(27.4)	(11.0)	(12.0)
Amortization of Prior Service Credit	—	—	(7.5)	(7.5)
Amortization of Net Actuarial Loss	5.3	7.9	2.8	1.4
Net Periodic Benefit Cost (Credit)	$ 3.2	$ 5.1	$ (8.5)	$ (11.1)

I&M

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 3.3	$ 3.4	$ 0.3	$ 0.4
Interest Cost	6.0	5.6	1.5	1.4
Expected Return on Plan Assets	(9.1)	(9.0)	(2.8)	(3.1)
Amortization of Prior Service Credit	—	—	(2.4)	(2.4)
Amortization of Net Actuarial Loss	1.6	2.5	0.7	0.3
Net Periodic Benefit Cost (Credit)	$ 1.8	$ 2.5	$ (2.7)	$ (3.4)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 10.0	$ 10.2	$ 1.0	$ 1.2
Interest Cost	17.9	16.6	4.4	4.1
Expected Return on Plan Assets	(27.5)	(26.8)	(8.5)	(9.3)
Amortization of Prior Service Credit	—	—	(7.1)	(7.1)
Amortization of Net Actuarial Loss	4.9	7.4	2.0	0.9
Net Periodic Benefit Cost (Credit)	$ 5.3	$ 7.4	$ (8.2)	$ (10.2)

OPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 1.9	$ 2.0	$ 0.2	$ 0.2
Interest Cost	4.8	4.4	1.4	1.3
Expected Return on Plan Assets	(7.3)	(7.2)	(2.7)	(2.9)
Amortization of Prior Service Credit	—	—	(1.8)	(1.7)
Amortization of Net Actuarial Loss	1.3	2.0	0.6	0.3
Net Periodic Benefit Cost (Credit)	$ 0.7	$ 1.2	$ (2.3)	$ (2.8)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 5.9	$ 5.8	$ 0.6	$ 0.7
Interest Cost	14.3	13.3	4.1	3.9
Expected Return on Plan Assets	(22.0)	(21.6)	(8.1)	(8.8)
Amortization of Prior Service Credit	—	—	(5.2)	(5.2)
Amortization of Net Actuarial Loss	4.0	6.0	1.9	0.8
Net Periodic Benefit Cost (Credit)	$ 2.2	$ 3.5	$ (6.7)	$ (8.6)

PSO

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 1.6	$ 1.7	$ 0.2	$ 0.1
Interest Cost	2.6	2.5	0.7	0.6
Expected Return on Plan Assets	(4.0)	(4.0)	(1.3)	(1.3)
Amortization of Prior Service Credit	—	—	(1.1)	(1.1)
Amortization of Net Actuarial Loss	0.7	1.1	0.3	0.1
Net Periodic Benefit Cost (Credit)	$ 0.9	$ 1.3	$ (1.2)	$ (1.6)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 4.9	$ 5.3	$ 0.5	$ 0.5
Interest Cost	7.9	7.4	2.0	1.8
Expected Return on Plan Assets	(12.2)	(12.1)	(3.9)	(4.1)
Amortization of Prior Service Credit	—	—	(3.2)	(3.2)
Amortization of Net Actuarial Loss	2.2	3.3	0.9	0.4
Net Periodic Benefit Cost (Credit)	$ 2.8	$ 3.9	$ (3.7)	$ (4.6)

SWEPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 2.1	$ 2.4	$ 0.2	$ 0.2
Interest Cost	3.1	2.8	0.7	0.7
Expected Return on Plan Assets	(4.4)	(4.4)	(1.5)	(1.6)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	0.9	1.3	0.4	0.2
Net Periodic Benefit Cost (Credit)	$ 1.7	$ 2.1	$ (1.5)	$ (1.8)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Service Cost	$ 6.4	$ 7.0	$ 0.6	$ 0.7
Interest Cost	9.3	8.5	2.3	2.1
Expected Return on Plan Assets	(13.3)	(13.1)	(4.5)	(4.8)
Amortization of Prior Service Credit	—	—	(3.9)	(3.9)
Amortization of Net Actuarial Loss	2.6	3.8	1.1	0.5
Net Periodic Benefit Cost (Credit)	$ 5.0	$ 6.2	$ (4.4)	$ (5.4)

8. 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 AEP Texas and OPCo.
- OPCo purchases energy and capacity to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

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

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, interest expense, income tax expense and other nonallocated costs.

The tables below present AEP's reportable segment income statement information for the three and nine months ended September 30, 2019 and 2018 and reportable segment balance sheet information as of September 30, 2019 and December 31, 2018.

	Three Months Ended September 30, 2019						
	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	$ 2,598.9	$ 1,147.3	$ 65.5	$ 501.2	$ 2.1	$ —	$ 4,315.0
Other Operating Segments	46.6	39.3	207.5	32.5	22.3	(348.2)	—
Total Revenues	$ 2,645.5	$ 1,186.6	$ 273.0	$ 533.7	$ 24.4	$ (348.2)	$ 4,315.0
Net Income (Loss)	$ 438.4	$ 133.7	$ 127.0	$ 88.7	$ (53.9)	$ —	$ 733.9

	Three Months Ended September 30, 2018						
	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	$ 2,610.2	$ 1,180.9	$ 51.9	$ 486.5	$ 3.6	$ —	$ 4,333.1
Other Operating Segments	26.5	30.6	135.3	35.1	20.1	(247.6)	—
Total Revenues	$ 2,636.7	$ 1,211.5	$ 187.2	$ 521.6	$ 23.7	$ (247.6)	$ 4,333.1
Net Income (Loss)	$ 345.6	$ 145.2	$ 74.2	$ 5.1	$ 9.6	$ —	$ 579.7

	Nine Months Ended September 30, 2019						
	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	$ 7,087.6	$ 3,328.7	$ 196.5	$ 1,323.8	$ 8.8	$ —	$ 11,945.4
Other Operating Segments	85.0	125.6	611.8	104.4	64.9	(991.7)	—
Total Revenues	$ 7,172.6	$ 3,454.3	$ 808.3	$ 1,428.2	$ 73.7	$ (991.7)	$ 11,945.4
Net Income (Loss)	$ 920.8	$ 421.6	$ 407.6	$ 133.1	$ (116.0)	$ —	$ 1,767.1

	Nine Months Ended September 30, 2018						
	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	$ 7,332.4	$ 3,450.0	$ 196.5	$ 1,399.3	$ 16.4	$ —	$ 12,394.6
Other Operating Segments	61.3	60.9	408.7	88.1	55.1	(674.1)	—
Total Revenues	$ 7,393.7	$ 3,510.9	$ 605.2	$ 1,487.4	$ 71.5	$ (674.1)	$ 12,394.6
Net Income (Loss)	$ 856.3	$ 384.6	$ 280.9	$ 61.8	$ (17.1)	$ —	$ 1,566.5

	September 30, 2019						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$ 46,739.8	$ 19,283.9	$ 9,700.4	$ 1,661.6	$ 421.7	$ (354.5) (b)	$ 77,452.9
Accumulated Depreciation and Amortization	14,359.3	3,907.3	383.8	99.8	196.4	(186.4) (b)	18,760.2
Total Property Plant and Equipment - Net	$ 32,380.5	$ 15,376.6	$ 9,316.6	$ 1,561.8	$ 225.3	$ (168.1) (b)	$ 58,692.7
Total Assets	$ 40,746.1	$ 17,967.6	$ 10,606.7	$ 3,315.9	$ 5,002.3 (c)	$ (3,737.9) (b) (d)	$ 73,900.7
Long-term Debt Due Within One Year:							
Nonaffiliated	$ 687.4	$ 391.5	$ 249.0	$ —	$ (0.2) (e)	$ —	$ 1,327.7
Long-term Debt:							
Affiliated	59.0	—	—	32.2	—	(91.2)	—
Nonaffiliated	12,161.1	5,868.9	3,426.9	(0.3)	3,096.9	—	24,553.5
Total Long-term Debt	$ 12,907.5	$ 6,260.4	$ 3,675.9	$ 31.9	$ 3,096.7 (e)	$ (91.2)	$ 25,881.2

	December 31, 2018						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$ 45,365.1	$ 18,126.7	$ 8,659.5	$ 893.3	$ 395.2	$ (354.6) (b)	$ 73,085.2
Accumulated Depreciation and Amortization	13,822.5	3,833.7	282.8	47.0	186.6	(186.5) (b)	17,986.1
Total Property Plant and Equipment - Net	$ 31,542.6	$ 14,293.0	$ 8,376.7	$ 846.3	$ 208.6	$ (168.1) (b)	$ 55,099.1
Total Assets	$ 38,874.3	$ 17,083.4	$ 9,543.7	$ 1,979.7	$ 4,036.5 (c)	$ (2,714.8) (b) (d)	$ 68,802.8
Long-term Debt Due Within One Year:							
Nonaffiliated	$ 1,066.3	$ 549.1	$ 85.0	$ 0.1	$ (2.0) (e)	$ —	$ 1,698.5
Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—
Nonaffiliated	11,442.7	5,048.8	2,888.6	(0.3)	2,268.4	—	21,648.2
Total Long-term Debt	$ 12,559.0	$ 5,597.9	$ 2,973.6	$ 32.0	$ 2,266.4 (e)	$ (82.2)	$ 23,346.7

(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 other nonallocated costs.
(b) Includes eliminations due to an intercompany finance lease.
(c) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(d) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.
(e) Amounts reflect the impact of fair value hedge accounting. See "Accounting for Fair Value Hedging Strategies" section of Note 10 for additional information.

Registrant Subsidiaries' Reportable Segments (Applies to all Registrant Subsidiaries except AEPTCo)

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 integrated electricity transmission and distribution business for AEP Texas and OPCo. 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.

AEPTCo's Reportable Segments

AEPTCo Parent is the holding company of seven FERC-regulated transmission-only electric utilities. The seven State Transcos have been identified as operating segments of AEPTCo under the accounting guidance for "Segment Reporting." The State Transcos business consists of developing, constructing and operating transmission facilities at the request of the RTOs in which they operate and in replacing and upgrading facilities, assets and components of the existing AEP transmission system as needed to maintain reliability standards and provide service to AEP's wholesale and retail customers. The State Transcos are regulated for rate-making purposes exclusively by the FERC and earn revenues through tariff rates charged for the use of their electric transmission systems.

AEPTCo's Chief Operating Decision Maker makes operating decisions, allocates resources to and assesses performance based on these operating segments. The State Transcos operating segments all have similar economic characteristics and meet all of the criteria under the accounting guidance for "Segment Reporting" to be aggregated into one operating segment. As a result, AEPTCo has one reportable segment. The remainder of AEPTCo's activity is presented in AEPTCo Parent. While not considered a reportable segment, AEPTCo Parent represents the activity of the holding company which primarily relates to debt financing activity and general corporate activities.

The tables below present AEPTCo's reportable segment income statement information for the three and nine months ended September 30, 2019 and 2018 and reportable segment balance sheet information as of September 30, 2019 and December 31, 2018.

	Three Months Ended September 30, 2019			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 54.0	$ —	$ —	$ 54.0
Sales to AEP Affiliates	205.7	—	—	205.7
Other Revenues	—	—	—	—
Total Revenues	$ 259.7	$ —	$ —	$ 259.7
Interest Income	$ 0.4	$ 32.3	$ (31.9) (a)	$ 0.8
Interest Expense	26.4	31.9	(31.9) (a)	26.4
Income Tax Expense	30.0	0.1	—	30.1
Net Income	$ 107.3	$ 0.3 (b)	$ —	$ 107.6

	Three Months Ended September 30, 2018			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 46.0	$ —	$ —	$ 46.0
Sales to AEP Affiliates	148.4	—	—	148.4
Other Revenues	—	—	—	—
Total Revenues	$ 194.4	$ —	$ —	$ 194.4
Interest Income	$ 0.2	$ 26.0	$ (25.7) (a)	$ 0.5
Interest Expense	19.8	25.7	(25.7) (a)	19.8
Income Tax Expense	18.4	(0.8)	—	17.6
Net Income	$ 77.1	$ 1.0 (b)	$ —	$ 78.1

	Nine Months Ended September 30, 2019			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Revenues from:				
External Customers	$ 162.1	$ —	$ —	$ 162.1
Sales to AEP Affiliates	608.0	—	—	608.0
Other Revenues	—	—	—	—
Total Revenues	$ 770.1	$ —	$ —	$ 770.1
Interest Income	$ 0.8	$ 89.7	$ (88.4) (a)	$ 2.1
Interest Expense	69.5	88.4	(88.4) (a)	69.5
Income Tax Expense	90.5	0.2	—	90.7
Net Income	$ 347.1	$ 0.8 (b)	$ —	$ 347.9

	Nine Months Ended September 30, 2018			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Revenues from:				
External Customers	$ 132.3	$ —	$ —	$ 132.3
Sales to AEP Affiliates	453.8	—	—	453.8
Other Revenues	0.1	—	—	0.1
Total Revenues	$ 586.2	$ —	$ —	$ 586.2
Interest Income	$ 0.4	$ 76.2	$ (75.3) (a)	$ 1.3
Interest Expense	60.7	75.3	(75.3) (a)	60.7
Income Tax Expense	63.7	—	—	63.7
Net Income	$ 243.6	$ 0.6 (b)	$ —	$ 244.2

	September 30, 2019			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Total Transmission Property	$ 9,267.4	$ —	$ —	$ 9,267.4
Accumulated Depreciation and Amortization	368.8	—	—	368.8
Total Transmission Property – Net	$ 8,898.6	$ —	$ —	$ 8,898.6
Notes Receivable - Affiliated	$ —	$ 3,511.9	$ (3,511.9) (c)	$ —
Total Assets	$ 9,363.5	$ 3,589.0 (d)	$ (3,599.8) (e)	$ 9,352.7
Total Long-term Debt	$ 3,550.0	$ 3,511.9	$ (3,550.0) (c)	$ 3,511.9

	December 31, 2018			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Total Transmission Property	$ 8,268.1	$ —	$ —	$ 8,268.1
Accumulated Depreciation and Amortization	271.9	—	—	271.9
Total Transmission Property – Net	$ 7,996.2	$ —	$ —	$ 7,996.2
Notes Receivable - Affiliated	$ —	$ 2,823.0	$ (2,823.0) (c)	$ —
Total Assets	$ 8,406.8	$ 2,857.1 (d)	$ (2,869.8) (e)	$ 8,394.1

Total Long-term Debt	$	2,850.0	$	2,823.0	$	(2,850.0)	(c)	$	2,823.0

(a) Elimination of intercompany interest income/interest expense on affiliated debt arrangement.
(b) Includes the elimination of AEPTCo Parent’s equity earnings in the State Transcos.
(c) Elimination of intercompany debt.
(d) Includes the elimination of AEPTCo Parent’s investments in State Transcos.
(e) Primarily relates to the elimination of Notes Receivable from the State Transcos.

9. <u>DERIVATIVES AND HEDGING</u>

The disclosures in this note apply to all Registrants unless indicated otherwise. For the periods presented, AEPTCo did not have any derivative and hedging activity.

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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 and credit 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
September 30, 2019

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	424.3	—	94.7	37.1	7.3	21.6	6.9
Natural Gas	MMBtus	53.2	—	—	—	—	—	12.5
Heating Oil and Gasoline	Gallons	8.4	1.8	1.6	0.8	2.0	0.8	0.9
Interest Rate	USD	$ 140.1	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate	USD	$ 600.0	$ —	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2018

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	371.1	—	66.4	40.9	7.8	15.2	4.5
Natural Gas	MMBtus	87.9	—	4.0	2.3	—	—	15.2
Heating Oil and Gasoline	Gallons	7.4	1.5	1.4	0.7	1.8	0.7	0.8
Interest Rate	USD	$ 37.7	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate	USD	$ 500.0	$ —	$ —	$ —	$ —	$ —	$ —

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.

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. AEP netted cash collateral received from third-parties against short-term and long-term
risk management assets in the amounts of $0 million and $18 million as of September 30, 2019 and December 31, 2018, respectively. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $21 million and $4 million as of September 30, 2019 and December 31, 2018, respectively. The netted cash collateral from third-parties against short-term and long-term risk management assets and netted cash collateral paid to third-parties against short-term and long-term risk management liabilities were immaterial for the other Registrants as of September 30, 2019 and December 31, 2018.

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets:

AEP

Fair Value of Derivative Instruments
September 30, 2019

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (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	$ 337.0	$ 16.5	$ 1.9	$ 355.4	$ (168.7)	$ 186.7
Long-term Risk Management Assets	319.0	10.0	25.3	354.3	(55.3)	299.0
Total Assets	656.0	26.5	27.2	709.7	(224.0)	485.7
Current Risk Management Liabilities	213.4	36.4	0.2	250.0	(174.7)	75.3
Long-term Risk Management Liabilities	281.7	87.4	—	369.1	(70.5)	298.6
Total Liabilities	495.1	123.8	0.2	619.1	(245.2)	373.9
Total MTM Derivative Contract Net Assets (Liabilities)	$ 160.9	$ (97.3)	$ 27.0	$ 90.6	$ 21.2	$ 111.8

December 31, 2018

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (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	$ 397.5	$ 28.5	$ —	$ 426.0	$ (263.2)	$ 162.8
Long-term Risk Management Assets	276.4	16.0	—	292.4	(38.4)	254.0
Total Assets	673.9	44.5	—	718.4	(301.6)	416.8
Current Risk Management Liabilities	293.8	13.2	2.0	309.0	(254.0)	55.0
Long-term Risk Management Liabilities	225.7	56.1	15.4	297.2	(33.8)	263.4
Total Liabilities	519.5	69.3	17.4	606.2	(287.8)	318.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 154.4	$ (24.8)	$ (17.4)	$ 112.2	$ (13.8)	$ 98.4

AEP Texas

Fair Value of Derivative Instruments
September 30, 2019

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	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	0.4	(0.1)	0.3
Long-term Risk Management Liabilities	—	0.1	0.1
Total Liabilities	0.4	—	0.4
Total MTM Derivative Contract Net Liabilities	$ (0.4)	$ —	$ (0.4)

December 31, 2018

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	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	0.7	(0.5)	0.2
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.7	(0.5)	0.2
Total MTM Derivative Contract Net Assets (Liabilities)	$ (0.7)	$ 0.5	$ (0.2)

APCo

Fair Value of Derivative Instruments
September 30, 2019

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	$ 86.3	$ (29.8)	$ 56.5
Long-term Risk Management Assets	4.1	(3.9)	0.2
Total Assets	90.4	(33.7)	56.7
Current Risk Management Liabilities	32.3	(31.2)	1.1
Long-term Risk Management Liabilities	4.4	(4.1)	0.3
Total Liabilities	36.7	(35.3)	1.4
Total MTM Derivative Contract Net Assets	$ 53.7	$ 1.6	$ 55.3

December 31, 2018

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	$ 114.4	$ (57.2)	$ 57.2
Long-term Risk Management Assets	3.1	(2.2)	0.9
Total Assets	117.5	(59.4)	58.1

Current Risk Management Liabilities	56.7	(56.3)	0.4
Long-term Risk Management Liabilities	2.4	(2.2)	0.2
Total Liabilities	59.1	(58.5)	0.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 58.4	$ (0.9)	$ 57.5

I&M

Fair Value of Derivative Instruments
September 30, 2019

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	$ 30.5	$ (20.0)	$ 10.5
Long-term Risk Management Assets	2.7	(2.6)	0.1
Total Assets	33.2	(22.6)	10.6
Current Risk Management Liabilities	21.0	(20.8)	0.2
Long-term Risk Management Liabilities	2.7	(2.7)	—
Total Liabilities	23.7	(23.5)	0.2
Total MTM Derivative Contract Net Assets	$ 9.5	$ 0.9	$ 10.4

December 31, 2018

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	$ 50.4	$ (41.8)	$ 8.6
Long-term Risk Management Assets	2.0	(1.4)	0.6
Total Assets	52.4	(43.2)	9.2
Current Risk Management Liabilities	41.1	(40.8)	0.3
Long-term Risk Management Liabilities	1.6	(1.5)	0.1
Total Liabilities	42.7	(42.3)	0.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 9.7	$ (0.9)	$ 8.8

OPCo

Fair Value of Derivative Instruments
September 30, 2019

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	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	7.2	—	7.2
Long-term Risk Management Liabilities	105.7	—	105.7
Total Liabilities	112.9	—	112.9
Total MTM Derivative Contract Net Liabilities	$ (112.9)	$ —	$ (112.9)

December 31, 2018

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	—	—	—
Total Assets	—	—	—

Current Risk Management Liabilities	6.4	(0.6)	5.8
Long-term Risk Management Liabilities	93.8	—	93.8
Total Liabilities	100.2	(0.6)	99.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ (100.2)	$ 0.6	$ (99.6)

PSO

Fair Value of Derivative Instruments
September 30, 2019

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	$ 21.9	$ (0.2)	$ 21.7
Long-term Risk Management Assets	—	—	—
Total Assets	21.9	(0.2)	21.7
Current Risk Management Liabilities	0.5	(0.2)	0.3
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.5	(0.2)	0.3
Total MTM Derivative Contract Net Assets	$ 21.4	$ —	$ 21.4

December 31, 2018

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	$ 10.9	$ (0.5)	$ 10.4
Long-term Risk Management Assets	—	—	—
Total Assets	10.9	(0.5)	10.4
Current Risk Management Liabilities	1.7	(0.7)	1.0
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	1.7	(0.7)	1.0
Total MTM Derivative Contract Net Assets	$ 9.2	$ 0.2	$ 9.4

SWEPCo

Fair Value of Derivative Instruments
September 30, 2019

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	$ 9.8	$ (0.4)	$ 9.4
Long-term Risk Management Assets	—	—	—
Total Assets	9.8	(0.4)	9.4
Current Risk Management Liabilities	2.1	(0.4)	1.7
Long-term Risk Management Liabilities	3.0	—	3.0
Total Liabilities	5.1	(0.4)	4.7
Total MTM Derivative Contract Net Assets	$ 4.7	$ —	$ 4.7

December 31, 2018

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	$ 5.6	$ (0.8)	$ 4.8
Long-term Risk Management Assets	—	—	—
Total Assets	5.6	(0.8)	4.8

Current Risk Management Liabilities	1.5	(1.1)	0.4
Long-term Risk Management Liabilities	2.2	—	2.2
Total Liabilities	3.7	(1.1)	2.6
Total MTM Derivative Contract Net Assets	$ 1.9	$ 0.3	$ 2.2

(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) All derivative contracts subject to a master netting arrangement or similar agreement are 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 Three Months Ended September 30, 2019

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 0.5	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	21.0	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.2	0.2	—	—	—
Purchased Electricity for Resale	0.4	—	0.3	—	—	—	—
Other Operation	(0.1)	—	(0.1)	(0.1)	(0.1)	(0.1)	—
Maintenance	(0.2)	—	—	(0.1)	—	—	—
Regulatory Assets (a)	(4.8)	(0.2)	0.2	—	(2.6)	(0.1)	(1.6)
Regulatory Liabilities (a)	26.3	—	10.0	3.2	—	4.3	4.5
Total Gain (Loss) on Risk Management Contracts	$ 43.1	$ (0.2)	$ 10.6	$ 3.2	$ (2.7)	$ 4.1	$ 2.9

Amount of Gain (Loss) Recognized on Risk Management Contracts Three Months Ended September 30, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ (0.7)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	19.3	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.5)	(0.1)	—	—	—
Purchased Electricity for Resale	0.3	—	0.3	—	—	—	—
Other Operation	0.5	0.1	0.1	0.1	0.1	0.1	0.1
Maintenance	0.6	0.1	0.1	0.1	0.1	0.1	0.1
Regulatory Assets (a)	(14.0)	—	—	(3.5)	(9.3)	(0.6)	(0.6)
Regulatory Liabilities (a)	33.8	—	24.0	—	—	3.9	1.5
Total Gain (Loss) on Risk Management Contracts	$ 39.8	$ 0.2	$ 24.0	$ (3.4)	$ (9.1)	$ 3.5	$ 1.1

Amount of Gain (Loss) Recognized on Risk Management Contracts Nine Months Ended September 30, 2019

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 1.0	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	27.2	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.2	0.5	—	—	0.1
Purchased Electricity for Resale	1.6	—	1.4	0.1	—	—	—
Other Operation	(0.6)	(0.1)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)
Maintenance	(0.6)	(0.1)	(0.1)	(0.1)	(0.1)	—	(0.1)
Regulatory Assets (a)	(19.4)	0.3	0.4	0.2	(19.8)	0.9	(0.4)
Regulatory Liabilities (a)	64.5	—	(5.3)	17.2	—	26.6	22.9
Total Gain (Loss) on Risk Management Contracts	$ 73.7	$ 0.1	$ (3.5)	$ 17.8	$ (20.1)	$ 27.4	$ 22.4

Amount of Gain (Loss) Recognized on Risk Management Contracts Nine Months Ended September 30, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ (9.4)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	31.7	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(1.3)	(7.8)	—	—	0.1
Purchased Electricity for Resale	8.3	—	7.3	0.8	—	—	—
Other Operation	1.3	0.3	0.2	0.2	0.3	0.2	0.2
Maintenance	1.5	0.3	0.3	0.2	0.3	0.2	0.2
Regulatory Assets (a)	29.2	—	—	(0.3)	31.8	(0.6)	(1.7)
Regulatory Liabilities (a)	206.2	—	127.3	11.7	0.6	34.8	7.6
Total Gain on Risk Management Contracts	$ 268.8	$ 0.6	$ 133.8	$ 4.8	$ 33.0	$ 34.6	$ 6.4

(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.”

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 impacts recognized on the balance sheets related to the hedged items in fair value hedging relationships:

	Carrying Amount of the Hedged Assets/(Liabilities)		**Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Assets/(Liabilities)**	
	September 30, 2019	**December 31, 2018**	**September 30, 2019**	**December 31, 2018**
	(in millions)			
Long-term Debt (a)	$ (521.2)	$ (478.3)	$ (25.1)	$ 17.4

(a) Amounts included on the balance sheets within Long-term Debt Due within One Year and Long-term Debt, respectively.

The pretax effects of fair value hedge accounting on income were as follows:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2019	**2018**	**2019**	**2018**
	(in millions)			
Gain (Loss) on Interest Rate Contracts:				
Gain (Loss) on Fair Value Hedging Instruments (a)	$ 13.2	$ (6.3)	$ 42.5	$ (28.1)
Gain (Loss) on Fair Value Portion of Long-term Debt (a)	(13.2)	6.3	(42.5)	28.1

(a) Gain (Loss) is included in Interest Expense on the statements of income.

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 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.

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 the three and nine months ended September 30, 2019 and 2018, AEP applied cash flow hedging to outstanding power derivatives. During the three and nine months ended September 30, 2019 and 2018, the Registrant Subsidiaries did not apply 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 the three and nine months ended September 30, 2019 AEP applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the three and nine months ended September 30, 2018 AEP and SWEPCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

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 - Comprehensive Income.

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

	September 30, 2019		December 31, 2018	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ (82.2)	$ (16.7) (a)	$ (23.0)	$ (12.6)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	(24.2)	(3.7)	10.4	(1.1)

(a) Includes $6 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC. See "Sempra Renewables LLC" section of Note 14 for additional information.

As of September 30, 2019 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 123 months and 135 months for commodity and interest rate hedges, respectively.

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Balance Sheets

	September 30, 2019		December 31, 2018	
	Interest Rate			
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)			
AEP Texas	$ (3.6)	$ (1.1)	$ (4.4)	$ (1.1)
APCo	1.1	0.9	1.8	0.9
I&M	(10.3)	(1.6)	(11.5)	(1.6)
OPCo	—	—	1.0	1.0
PSO	1.4	1.0	2.1	1.0
SWEPCo	(2.2)	(1.5)	(3.3)	(1.5)

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 mitigates 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 credit agency ratings 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. Some master agreements include margining, which requires a counterparty 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 default including a failure or inability to post collateral when required.

Collateral Triggering Events

Credit Downgrade Triggers (Applies to AEP, APCo, I&M, PSO and SWEPCo)

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. The Registrants have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. The Registrants had no derivative contracts with collateral triggering events in a net liability position as of September 30, 2019 and December 31, 2018, respectively.

Cross-Default Triggers (Applies to AEP, APCo, I&M and SWEPCo)

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:

	September 30, 2019		
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	$ 261.0	$ 3.4	$ 230.7
APCo	3.9	—	0.2
I&M	2.3	—	0.1
SWEPCo	4.7	—	2.8

	December 31, 2018		
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	$ 225.5	$ 1.8	$ 181.0
APCo	0.9	—	—
I&M	0.5	—	—
SWEPCo	2.3	—	2.3

10. FAIR VALUE MEASUREMENTS

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

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

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 derivatives 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 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 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 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. 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.

__Fair Value Measurements of Long-term Debt (Applies to all Registrants)__

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 fair value of AEP's Equity Units (Level 1) are valued based on publicly traded securities issued by AEP.

The book values and fair values of Long-term Debt are summarized in the following table:

	September 30, 2019		December 31, 2018	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
		(in millions)		
AEP (a)	$ 25,881.2	$ 29,729.1	$ 23,346.7	$ 24,093.9
AEP Texas	4,146.5	4,631.5	3,881.3	3,964.6
AEPTCo	3,511.9	3,984.9	2,823.0	2,782.4
APCo	4,362.9	5,370.2	4,062.6	4,473.3
I&M	3,031.5	3,497.3	3,035.4	3,070.2
OPCo	2,113.9	2,618.5	1,716.6	1,919.7
PSO	1,386.4	1,632.9	1,287.0	1,361.9
SWEPCo	2,656.9	2,983.0	2,713.4	2,670.2

(a) The fair value amount includes debt related to AEP's Equity Units issued in March 2019 and has a fair value of $887 million as of September 30, 2019. See "Equity Units" section of Note 13 for additional information.

__Fair Value Measurements of Other Temporary Investments (Applies to AEP)__

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS.

The following is a summary of Other Temporary Investments:

	September 30, 2019			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash and Other Cash Deposits (a)	$ 160.1	$ —	$ —	$ 160.1
Fixed Income Securities – Mutual Funds (b)	133.4	—	(0.2)	133.2
Equity Securities – Mutual Funds	28.5	17.6	—	46.1
Total Other Temporary Investments	$ 322.0	$ 17.6	$ (0.2)	$ 339.4

	December 31, 2018			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash and Other Cash Deposits (a)	$ 230.6	$ —	$ —	$ 230.6
Fixed Income Securities – Mutual Funds (b)	106.6	—	(2.3)	104.3
Equity Securities – Mutual Funds	17.8	16.4	—	34.2
Total Other Temporary Investments	$ 355.0	$ 16.4	$ (2.3)	$ 369.1

(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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Proceeds from Investment Sales	$ 2.8	$ —	$ 2.8	$ —
Purchases of Investments	26.9	0.8	35.8	2.2
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 three and nine months ended September 30, 2018, see Note 3 - Comprehensive Income.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

Nuclear decommissioning and SNF trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and SNF 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. With the adoption of ASU 2016-01, effective January 2018, available-for-sale classification only applies to investment in debt securities. Additionally, the adoption of ASU 2016-01 required changes in fair value of equity securities to be recognized in earnings. However, due to the regulatory treatment described below, this is not applicable for I&M’s trust fund securities.

Other-than-temporary impairments for investments in debt 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, unrealized losses 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.

The following is a summary of nuclear trust fund investments:

	September 30, 2019			December 31, 2018		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 17.4	$ —	$ —	$ 22.5	$ —	$ —
Fixed Income Securities:						
United States Government	1,047.4	67.8	(5.8)	996.1	26.7	(7.1)
Corporate Debt	68.6	6.1	(1.7)	52.4	1.1	(1.9)
State and Local Government	7.5	0.7	(0.2)	8.6	0.6	(0.2)
Subtotal Fixed Income Securities	1,123.5	74.6	(7.7)	1,057.1	28.4	(9.2)
Equity Securities - Domestic (a)	1,694.3	1,037.7	—	1,395.3	766.3	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,835.2	$ 1,112.3	$ (7.7)	$ 2,474.9	$ 794.7	$ (9.2)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $1 billion and $784 million and unrealized losses of $9 million and $18 million as of September 30, 2019 and December 31, 2018, respectively. AEP adopted ASU 2016-01 during the first quarter of 2018 by means of a modified retrospective approach. Due to the adoption of the ASU, Other-Than-Temporary Impairments are no longer applicable to Equity Securities with readily determinable fair values.

The following table provides the securities activity within the decommissioning and SNF trusts:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Proceeds from Investment Sales	$ 671.9	$ 513.1	$ 871.4	$ 1,550.9
Purchases of Investments	689.1	521.2	915.7	1,589.0
Gross Realized Gains on Investment Sales	10.9	3.9	26.6	27.7
Gross Realized Losses on Investment Sales	7.1	3.5	15.1	22.2

The base cost of fixed income securities was $1 billion and $1 billion as of September 30, 2019 and December 31, 2018, respectively. The base cost of equity securities was $657 million and $629 million as of September 30, 2019 and December 31, 2018, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2019 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 334.9
After 1 year through 5 years	390.9
After 5 years through 10 years	199.2
After 10 years	198.5
Total	$ 1,123.5

Fair Value Measurements of Financial Assets and Liabilities

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
September 30, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 152.9	$ —	$ —	$ 7.2	$ 160.1
Fixed Income Securities – Mutual Funds	133.2	—	—	—	133.2
Equity Securities – Mutual Funds (b)	46.1	—	—	—	46.1
Total Other Temporary Investments	332.2	—	—	7.2	339.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	5.6	228.2	407.7	(195.3)	446.2
Cash Flow Hedges:					
Commodity Hedges (c)	—	17.6	2.9	(8.2)	12.3
Interest Rate Hedges	—	1.9	—	—	1.9
Fair Value Hedges	—	25.3	—	—	25.3
Total Risk Management Assets	5.6	273.0	410.6	(203.5)	485.7
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	9.4	—	—	8.0	17.4
Fixed Income Securities:					
United States Government	—	1,047.4	—	—	1,047.4
Corporate Debt	—	68.6	—	—	68.6
State and Local Government	—	7.5	—	—	7.5
Subtotal Fixed Income Securities	—	1,123.5	—	—	1,123.5
Equity Securities – Domestic (b)	1,694.3	—	—	—	1,694.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,703.7	1,123.5	—	8.0	2,835.2
Total Assets	$ 2,041.5	$ 1,396.5	$ 410.6	$ (188.3)	$ 3,660.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 5.1	$ 243.9	$ 231.6	$ (216.5)	$ 264.1
Cash Flow Hedges:					
Commodity Hedges (c)	—	49.1	68.7	(8.2)	109.6
Fair Value Hedges	—	0.2	—	—	0.2
Total Risk Management Liabilities	$ 5.1	$ 293.2	$ 300.3	$ (224.7)	$ 373.9

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 221.5	$ —	$ —	$ 9.1	$ 230.6
Fixed Income Securities – Mutual Funds	104.3	—	—	—	104.3
Equity Securities – Mutual Funds (b)	34.2	—	—	—	34.2
Total Other Temporary Investments	360.0	—	—	9.1	369.1
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	3.8	326.5	340.9	(288.5)	382.7
Cash Flow Hedges:					
Commodity Hedges (c)	—	24.1	12.7	(2.7)	34.1
Total Risk Management Assets	3.8	350.6	353.6	(291.2)	416.8
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	12.3	—	—	10.2	22.5
Fixed Income Securities:					
United States Government	—	996.1	—	—	996.1
Corporate Debt	—	52.4	—	—	52.4
State and Local Government	—	8.6	—	—	8.6
Subtotal Fixed Income Securities	—	1,057.1	—	—	1,057.1
Equity Securities – Domestic (b)	1,395.3	—	—	—	1,395.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,407.6	1,057.1	—	10.2	2,474.9
Total Assets	$ 1,771.4	$ 1,407.7	$ 353.6	$ (271.9)	$ 3,260.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 4.2	$ 327.0	$ 185.6	$ (274.7)	$ 242.1
Cash Flow Hedges:					
Commodity Hedges (c)	—	24.8	36.8	(2.7)	58.9
Fair Value Hedges	—	17.4	—	—	17.4
Total Risk Management Liabilities	$ 4.2	$ 369.2	$ 222.4	$ (277.4)	$ 318.4

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 114.3	$ —	$ —	$ —	$ 114.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.4	$ —	$ —	$ 0.4

December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 156.7	$ —	$ —	$ —	$ 156.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.7	$ —	$ (0.5)	$ 0.2

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 17.1	$ —	$ —	$ —	$ 17.1
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	31.4	57.3	(32.0)	56.7
Total Assets	$ 17.1	$ 31.4	$ 57.3	$ (32.0)	$ 73.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 33.2	$ 1.8	$ (33.6)	$ 1.4

December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 25.6	$ —	$ —	$ —	$ 25.6
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	0.1	59.1	58.3	(59.4)	58.1
Total Assets	$ 25.7	$ 59.1	$ 58.3	$ (59.4)	$ 83.7
Liabilities:					

Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 0.2	$ 58.4	$ 0.5	$ (58.5)	$ 0.6

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 21.9	$ 10.2	$ (21.5)	$ 10.6
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	9.4	—	—	8.0	17.4
Fixed Income Securities:					
United States Government	—	1,047.4	—	—	1,047.4
Corporate Debt	—	68.6	—	—	68.6
State and Local Government	—	7.5	—	—	7.5
Subtotal Fixed Income Securities	—	1,123.5	—	—	1,123.5
Equity Securities - Domestic (b)	1,694.3	—	—	—	1,694.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,703.7	1,123.5	—	8.0	2,835.2
Total Assets	$ 1,703.7	$ 1,145.4	$ 10.2	$ (13.5)	$ 2,845.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 21.3	$ 1.3	$ (22.4)	$ 0.2

December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 42.1	$ 10.3	$ (43.2)	$ 9.2
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	12.3	—	—	10.2	22.5
Fixed Income Securities:					
United States Government	—	996.1	—	—	996.1
Corporate Debt	—	52.4	—	—	52.4
State and Local Government	—	8.6	—	—	8.6
Subtotal Fixed Income Securities	—	1,057.1	—	—	1,057.1
Equity Securities - Domestic (b)	1,395.3	—	—	—	1,395.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,407.6	1,057.1	—	10.2	2,474.9
Total Assets	$ 1,407.6	$ 1,099.2	$ 10.3	$ (33.0)	$ 2,484.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 0.1	$ 41.2	$ 1.4	$ (42.3)	$ 0.4

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2019

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.4	$ 112.5	$ —	$ 112.9

December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 27.6	$ —	$ —	$ —	$ 27.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.8	$ 99.4	$ (0.6)	$ 99.6

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 22.0	$ (0.3)	$ 21.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 0.4	$ (0.3)	$ 0.3

December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 10.8	$ (0.4)	$ 10.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 1.3	$ (0.6)	$ 1.0

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 9.8	$ (0.4)	$ 9.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 4.9	$ (0.4)	$ 4.7

December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 5.6	$ (0.8)	$ 4.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.4	$ 3.3	$ (1.1)	$ 2.6

(a) Amounts in "Other'' column primarily represent cash deposits in bank accounts with financial institutions or 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 September 30, 2019 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 2 matures $(6) million in 2019, $(8) million in periods 2020-2022 and $(1) million in periods 2025-2032; Level 3 matures $40 million in 2019, $114 million in periods 2020-2022, $26 million in periods 2023-2024 and $(4) million in periods 2025-2032. 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, 2018 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 2 matures $(4) million in 2019, $1 million in periods 2020-2022, $1 million in periods 2023-2024 and $1 million in periods 2025-2032; Level 3 matures $108 million in 2019, $37 million in periods 2020-2022, $23 million in periods 2023-2024 and $(12) million in periods 2025-2032. 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 three and nine months ended September 30, 2019 and 2018.

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:

Three Months Ended September 30, 2019	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2019	$ 112.7	$ 68.5	$ 12.3	$ (111.5)	$ 27.8	$ 8.5
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	30.2	13.8	3.1	—	4.1	3.6
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	2.9	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	22.1	—	—	—	—	—
Settlements	(67.4)	(28.1)	(7.2)	1.1	(11.2)	(6.7)
Transfers into Level 3 (c) (d)	3.5	—	—	—	—	—
Transfers out of Level 3 (d)	6.6	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	(0.3)	1.3	0.7	(2.1)	0.9	(0.5)
Balance as of September 30, 2019	$ 110.3	$ 55.5	$ 8.9	$ (112.5)	$ 21.6	$ 4.9

Three Months Ended September 30, 2018	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2018	$ 172.3	$ 60.0	$ 13.2	$ (86.9)	$ 24.3	$ 4.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	19.9	9.0	1.9	—	3.7	1.7
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	1.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	10.4	—	—	—	—	—
Settlements	(56.0)	(19.8)	(5.5)	0.6	(10.8)	(2.7)
Transfers into Level 3 (c) (d)	2.3	—	—	—	—	—
Transfers out of Level 3 (d)	(1.2)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	12.0	17.3	(0.2)	(8.9)	0.4	(0.4)
Balance as of September 30, 2018	$ 161.2	$ 66.5	$ 9.4	$ (95.2)	$ 17.6	$ 3.5

Nine Months Ended September 30, 2019	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2018	$ 131.2	$ 57.8	$ 8.9	$ (99.4)	$ 9.5	$ 2.3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	14.6	(14.1)	4.6	(0.9)	13.5	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	32.9	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(42.8)	—	—	—	—	—
Settlements	(114.6)	(41.9)	(12.6)	4.6	(23.0)	(10.1)
Transfers into Level 3 (c) (d)	0.4	—	—	—	—	—
Transfers out of Level 3 (d)	1.4	(0.7)	(0.4)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	87.2	54.4	8.4	(16.8)	21.6	6.7
Balance as of September 30, 2019	$ 110.3	$ 55.5	$ 8.9	$ (112.5)	$ 21.6	$ 4.9

Nine Months Ended September 30, 2018	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2017	$ 40.3	$ 24.7	$ 7.6	$ (132.4)	$ 6.2	$ 5.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	150.9	104.4	14.7	1.3	18.1	(4.8)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	9.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	16.4	—	—	—	—	—
Settlements	(212.3)	(128.3)	(21.9)	3.0	(24.3)	(1.3)
Transfers into Level 3 (c) (d)	16.5	—	—	—	—	—
Transfers out of Level 3 (d)	(2.5)	—	(0.3)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	142.4	65.7	9.3	32.9	17.6	3.7
Balance as of September 30, 2018	$ 161.2	$ 66.5	$ 9.4	$ (95.2)	$ 17.6	$ 3.5

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents existing assets or liabilities that were previously categorized as Level 2.
(d) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(e) 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 or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

AEP

Significant Unobservable Inputs
September 30, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 298.8	$ 286.8	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 180.10	$ 31.34
Natural Gas Contracts	—	4.5	Discounted Cash Flow	Forward Market Price (b)	1.96	2.62	2.25
FTRs	111.8	9.0	Discounted Cash Flow	Forward Market Price (a)	(10.40)	11.65	0.54
Total	$ 410.6	$ 300.3					

December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 257.1	$ 212.5	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 176.57	$ 33.07
Natural Gas Contracts	—	2.5	Discounted Cash Flow	Forward Market Price (b)	2.18	3.54	2.47
FTRs	96.5	7.4	Discounted Cash Flow	Forward Market Price (a)	(11.68)	17.79	1.09
Total	$ 353.6	$ 222.4					

APCo

Significant Unobservable Inputs
September 30, 2019

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 3.6	$ 1.1	Discounted Cash Flow	Forward Market Price	$ 12.93	$ 59.25	$ 31.28
FTRs	53.7	0.7	Discounted Cash Flow	Forward Market Price	(0.91)	10.14	1.63
Total	$ 57.3	$ 1.8					

December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 2.4	$ 0.5	Discounted Cash Flow	Forward Market Price	$ 16.82	$ 62.65	$ 37.00
FTRs	55.9	—	Discounted Cash Flow	Forward Market Price	0.10	15.16	3.27
Total	$ 58.3	$ 0.5					

I&M

Significant Unobservable Inputs
September 30, 2019

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 2.2	$ 0.7	Discounted Cash Flow	Forward Market Price	$ 12.93	$ 59.25	$ 31.28
FTRs	8.0	0.6	Discounted Cash Flow	Forward Market Price	(1.76)	7.26	0.87
Total	$ 10.2	$ 1.3					

December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 1.4	$ 0.9	Discounted Cash Flow	Forward Market Price	$ 16.82	$ 62.65	$ 37.00
FTRs	8.9	0.5	Discounted Cash Flow	Forward Market Price	(2.11)	6.21	1.06
Total	$ 10.3	$ 1.4					

OPCo

Significant Unobservable Inputs
September 30, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 112.5	Discounted Cash Flow	Forward Market Price	$ 27.47	$ 65.81	$ 40.30

December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 99.4	Discounted Cash Flow	Forward Market Price	$ 26.29	$ 62.74	$ 42.50

PSO

Significant Unobservable Inputs
September 30, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 22.0	$ 0.4	Discounted Cash Flow	Forward Market Price	$ (6.87)	$ 0.93	$ (2.19)

December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 10.8	$ 1.3	Discounted Cash Flow	Forward Market Price	$ (11.68)	$ 10.30	$ (1.40)

SWEPCo

Significant Unobservable Inputs
September 30, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Natural Gas Contracts	$ —	$ 4.5	Discounted Cash Flow	Forward Market Price (b)	$ 1.96	$ 2.62	$ 2.25
FTRs	9.8	0.4	Discounted Cash Flow	Forward Market Price (a)	(6.87)	0.93	(2.19)
Total	$ 9.8	$ 4.9					

December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average
	(in millions)						
Natural Gas Contracts	$ —	$ 2.5	Discounted Cash Flow	Forward Market Price (b)	$ 2.18	$ 3.54	$ 2.47
FTRs	5.6	0.8	Discounted Cash Flow	Forward Market Price (a)	(11.68)	10.30	(1.40)
Total	$ 5.6	$ 3.3					

(a) Represents market prices in dollars per MWh.
(b) Represents market prices in dollars per MMBtu.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts and FTRs for the Registrants as of September 30, 2019 and December 31, 2018:

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)

11. INCOME TAXES

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

Status of Tax Reform Regulatory Proceedings

For AEP's various regulatory jurisdictions where the regulatory effects of Tax Reform proceedings have not been fully resolved, the table below summarizes the current status. See Note 4 - Rate Matters for additional information related to regulatory filings in these jurisdictions.

Registrant (Jurisdiction)	Change in Tax Rate	Excess ADIT Subject to Normalization Requirements	Excess ADIT Not Subject to Normalization Requirements
AEP Texas (Texas-Distribution)	Order Issued	Order Issued	Order Issued – Partial (a)
AEP Texas (Texas-Transmission)	Order Issued	Case Pending	Case Pending
I&M (Michigan)	Order Issued	Case Pending	Case Pending
SWEPCo (Louisiana)	Case Pending – Rates Implemented (b)	Case Pending – Rates Implemented (b)	Case Pending – Rates Implemented (b)
SWEPCo (Texas)	Order Issued	To be addressed in a later filing	To be addressed in a later filing

(a) A portion of the Excess ADIT that is not subject to rate normalization requirements is addressed in a current pending case.
(b) Rates have been implemented through a filed formula rate plan that is subject to true-up and final commission approval.

Effective Tax Rates (ETR)

The Registrants' interim ETR reflect the estimated annual ETR for 2019 and 2018, adjusted for tax expense associated with certain discrete items. The interim ETR differ from the federal statutory tax rate of 21% primarily due to increased amortization of Excess ADIT, tax credits and other book/tax differences which are accounted for on a flow-through basis.

The Registrants include the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, the Registrants recognize the tax benefit discretely in the period recorded. The annual amount of Excess ADIT approved by the Registrant's regulatory commissions may not impact the ETR ratably during each interim period due to the variability of pretax book income between interim periods and the application of an annual estimated ETR.

The ETR for each of the Registrants are included in the following table. Significant variances in the ETR are described below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2019	2018	2019	2018
AEP	5.2 %	(16.2)%	1.7 %	5.6 %
AEP Texas	15.1 %	12.6 %	(25.3)%	14.9 %
AEPTCo	21.9 %	18.4 %	20.7 %	20.7 %
APCo	(3.9)%	(962.2)%	(19.1)%	(13.8)%
I&M	(2.7)%	15.9 %	(2.1)%	10.4 %
OPCo	13.9 %	(46.4)%	14.2 %	4.6 %
PSO	6.4 %	5.6 %	4.6 %	8.7 %
SWEPCo	(0.6)%	9.8 %	— %	11.4 %

AEP

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The increase in the ETR was primarily due to $71 million of decreased amortization of Excess ADIT not subject to normalization requirements and $14 million of increased state tax expense which impacted the ETR by 19.1% and 1.3%, respectively.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The decrease in the ETR was primarily due to $93 million of increased amortization of Excess ADIT not subject to normalization requirements which impacted the ETR by (4.5)%.

AEP Texas

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The increase in ETR was primarily due to significantly higher pretax book income which reduced the impact that favorable tax deductions had on the ETR.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The decrease in the ETR was primarily due to $59 million of increased amortization of Excess ADIT not subject to normalization requirements which impacted the ETR by (38.9)%. Amortization of Excess ADIT not subject to normalization requirements for the nine months ended September 30, 2019 reflects Tax Reform elements of the Stipulation and Settlement agreement approved by the PUCT in August 2018 and the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.

AEPTCo

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The increase in the ETR was primarily due to $3 million of increased state tax expense and $2 million of decreased amortization of Excess ADIT not subject to normalization requirements which impacted the ETR by 1.3% and 1%, respectively.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The ETR remained consistent for the nine months ended September 30, 2019 and 2018.

APCo

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The increase in the ETR was primarily due to $56 million of decreased amortization of Excess ADIT not subject to normalization requirements and $6 million of increased state tax expense which impacted the ETR by 947.3% and 34.8%, respectively. Amortization of Excess ADIT not subject to normalization requirements primarily decreased from the prior year due to the discrete impact of the West Virginia Tax Reform order which enabled APCo to utilize $73 million of Excess ADIT not subject to normalization requirements to offset certain regulatory asset balances in the third quarter of 2018.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The decrease in the ETR was primarily due to $9 million of increased amortization of Excess ADIT not subject to normalization requirements which impacted the ETR by (4.6)%. Amortization of Excess ADIT not subject to normalization requirements for the nine months ended September 30, 2019 reflects the October 2018 and March 2019 Virginia SCC Tax Reform orders as well as the August 2018 and February 2019 WVPSC orders.

I&M

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The decrease in the ETR was primarily due to $10 million of increased amortization of Excess ADIT, $3 million of increased favorable book/tax differences accounted for on a flow-through basis, $2 million of decreased state income tax expense and $1 million of increased parent company loss benefit which impacted the ETR by (11.3)%, (3.2)%, (1.8)% and (1.6)% respectively.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The decrease in the ETR was primarily due to $16 million of increased amortization of Excess ADIT not subject to normalization requirements and $12 million of increased favorable book/tax differences accounted for on a flow-through basis which impacted the ETR by (6.9)% and (4.8)%, respectively. Amortization of Excess ADIT not subject to normalization requirements for the nine months ended September 30, 2019 reflects the Tax Reform elements of the 2017 Indiana Base Rate Case approved by the IURC in May 2018.

OPCo

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The increase in the ETR was primarily due to $35 million of decreased amortization of Excess ADIT not subject to normalization requirements and $1 million of decreased parent company loss benefit which impacted the ETR by 60% and 2%, respectively. Amortization of Excess ADIT not subject to amortization requirements decreased from the prior year primarily due to the discrete impact of the Ohio Tax Reform order which enabled OPCo to utilize $38 million of Excess ADIT not subject to rate normalization requirements to offset certain regulatory asset balances in the third quarter of 2018.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The increase in the ETR was primarily due to $24 million of decreased amortization of Excess ADIT not subject to normalization requirements which impacted the ETR by 10.8%. Amortization of Excess ADIT not subject to amortization requirements decreased from the prior year primarily due to the discrete impact of the Ohio Tax Reform order which enabled OPCo to utilize $38 million of Excess ADIT not subject to rate normalization requirements to offset certain regulatory asset balances in the third quarter of 2018.

PSO

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The ETR remained comparable for the three months ended September 30, 2019 and 2018.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The decrease in the ETR was primarily due to $15 million of increased amortization of Excess ADIT not subject to normalization requirements which impacted the ETR by (6.8)%. Amortization of Excess ADIT not subject to normalization requirements for the nine months ended September 30, 2019 reflects the August 2018 OCC Tax Reform order as well as Tax Reform elements of the 2018 Oklahoma Base Rate Case approved by the OCC in March 2019.

SWEPCo

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The decrease in the ETR was primarily due to $11 million of increased amortization of Excess ADIT not subject to normalization requirements which impacted the ETR by (9.7)%. Amortization of Excess ADIT not subject to normalization requirements for the nine months ended September 30, 2019 reflects Tax Reform elements incorporated in the Louisiana 2018 Formula Rate Filing as well as the Arkansas Tax Reform order issued by the APSC in September 2018.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The decrease in the ETR was primarily due to $15 million of increased amortization of Excess ADIT not subject to normalization requirements which impacted the ETR by (10.4)%. Amortization of Excess ADIT not subject to normalization requirements for the nine months ended September 30, 2019 reflects Tax Reform elements incorporated in the Louisiana 2018 Formula Rate Filing as well as the Arkansas Tax Reform order issued by the APSC in September 2018.

Federal and State Income Tax Audit Status

AEP and subsidiaries are no longer subject to U.S. federal examination by the IRS for all years through 2013. During the IRS examination of years 2011 through 2014, the statute of limitations for these years was extended to coincide with the examination of 2015. During the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 and 2015 federal returns. Due to the amendment of these federal returns, the 2014 and 2015 years will remain open for possible IRS examination for only the items that were amended on the 2014 and 2015 federal returns. The IRS examination of 2016 began in October 2018 and concluded in March 2019.

State Tax Legislation (Applies to AEP, AEPTCo, I&M and OPCo)

In April 2018, the Kentucky legislature enacted House Bill (H.B.) 487. H.B. 487 adopts mandatory unitary combined reporting for state corporate income tax purposes applicable for taxable years beginning on or after January 1, 2019. H.B. 487 also adopts the 80% federal net operating loss (NOL) limitation under Internal Revenue Code Sec. 172(a) for NOLs generated after January 1, 2018 and the federal unlimited carryforward period for unused NOLs generated after January 1, 2018. In addition, H.B. 366 was also enacted in April 2018, which among other things, replaces the graduated corporate tax rate structure with a flat 5% tax rate for business income and adopts a single-sales factor apportionment formula for apportioning a corporation's business income to Kentucky. In the second quarter of 2018, AEP recorded an $18 million benefit to Income Tax Expense (Benefit) as a result of remeasuring Kentucky deferred taxes under a unitary filing group. The enacted legislation did not materially impact AEPTCo's, I&M's or OPCo's net income.

12. LEASES

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

The Registrants lease property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. As of the adoption date of ASU 2016-02, management elected not to separate non-lease components from associated lease components in accordance with the accounting guidance for "Leases." Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain the Registrant will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. When the implicit rate is not readily determinable, the Registrants measure their lease obligation using their estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Lease rentals for both operating and finance leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs were as follows:

Three Months Ended September 30, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 64.4	$ 4.0	$ 0.6	$ 4.9	$ 23.7	$ 4.9	$ 1.5	$ 1.8
Finance Lease Cost:								
Amortization of Right-of-Use Assets	16.5	1.5	0.1	2.0	1.6	1.1	0.8	2.8
Interest on Lease Liabilities	4.1	0.3	—	0.8	0.8	0.2	0.1	0.7
Total Lease Rental Costs (a)	$ 85.0	$ 5.8	$ 0.7	$ 7.7	$ 26.1	$ 6.2	$ 2.4	$ 5.3

Nine Months Ended September 30, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 200.3	$ 12.2	$ 1.7	$ 14.5	$ 70.0	$ 13.8	$ 5.0	$ 5.7
Finance Lease Cost:								
Amortization of Right-of-Use Assets	45.0	3.8	0.1	5.0	4.2	2.6	2.2	8.2
Interest on Lease Liabilities	12.2	1.0	—	2.2	2.3	0.5	0.4	2.2
Total Lease Rental Costs (a)	$ 257.5	$ 17.0	$ 1.8	$ 21.7	$ 76.5	$ 16.9	$ 7.6	$ 16.1

(a) Excludes variable and short-term lease costs, which were immaterial for the three and nine months ended September 30, 2019.

Supplemental information related to leases are shown in the tables below:

September 30, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	5.31	7.05	2.43	6.25	4.05	8.10	7.06	6.63
Finance Leases	5.87	6.86	0.58	6.33	6.72	6.58	6.24	5.34
Weighted-Average Discount Rate:								
Operating Leases	3.61%	3.79%	3.13%	3.67%	3.45%	3.79%	3.68%	3.80%
Finance Leases	6.02%	4.71%	9.33%	8.19%	8.61%	4.66%	4.73%	5.03%

Nine Months Ended September 30, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Cash paid for amounts included in the measurement of lease liabilities:								
Operating Cash Flows Used for Operating Leases	$ 163.6	$ 11.4	$ 1.7	$ 14.1	$ 52.5	$ 13.8	$ 4.9	$ 5.3
Operating Cash Flows Used for Finance Leases	11.0	1.0	—	2.2	2.2	0.5	0.4	1.1
Financing Cash Flows Used for Finance Leases	44.5	3.8	—	5.0	4.0	2.6	2.2	8.1
Non-cash Acquisitions Under Operating Leases	$ 108.9	$ 12.7	$ —	$ 8.6	$ 16.6	$ 34.6	$ 7.3	$ 10.6

The following tables show the property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on the Registrants' balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the Registrants' balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

September 30, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 134.9	$ —	$ —	$ 41.3	$ 28.5	$ —	$ 2.6	$ 34.2
Other Property, Plant and Equipment	335.9	41.9	0.2	18.4	37.1	24.7	20.7	50.0
Total Property, Plant and Equipment	470.8	41.9	0.2	59.7	65.6	24.7	23.3	84.2
Accumulated Amortization	162.7	10.9	0.2	17.8	22.8	6.6	9.1	26.2
Net Property, Plant and Equipment Under Finance Leases	$ 308.1	$ 31.0	$ —	$ 41.9	$ 42.8	$ 18.1	$ 14.2	$ 58.0
Obligations Under Finance Leases:								
Noncurrent Liability	$ 254.0	$ 25.8	$ —	$ 35.2	$ 37.1	$ 14.5	$ 11.0	$ 50.5
Liability Due Within One Year	61.4	5.2	—	6.7	6.0	3.6	3.2	11.2
Total Obligations Under Finance Leases	$ 315.4	$ 31.0	$ —	$ 41.9	$ 43.1	$ 18.1	$ 14.2	$ 61.7

September 30, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Assets	$ 990.0	$ 82.0	$ 4.6	$ 79.4	$ 295.3	$ 88.2	$ 37.1	$ 40.8
Obligations Under Operating Leases:								
Noncurrent Liability	$ 801.1	$ 71.1	$ 2.2	$ 64.8	$ 234.0	$ 75.9	$ 31.2	$ 32.5
Liability Due Within One Year	228.8	11.7	2.3	15.3	82.0	12.8	6.0	5.9
Total Obligations Under Operating Leases	$ 1,029.9	$ 82.8	$ 4.5	$ 80.1	$ 316.0	$ 88.7	$ 37.2	$ 38.4

Future minimum lease payments as of September 30, 2019 are presented on a rolling 12-month basis as shown in the tables below:

Finance Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Year 1	$ 76.8	$ 6.6	$ —	$ 9.6	$ 9.0	$ 4.3	$ 3.8	$ 13.0
Year 2	67.0	6.1	—	8.8	8.2	3.9	3.1	11.6
Year 3	58.0	5.3	—	8.1	7.6	3.2	2.3	10.6
Year 4	49.0	4.9	—	7.5	7.1	2.5	2.1	9.5
Year 5	50.0	4.1	—	7.0	6.7	2.1	1.7	14.8
Later Years	76.1	9.8	—	11.3	20.9	5.3	3.7	7.5
Total Future Minimum Lease Payments	376.9	36.8	—	52.3	59.5	21.3	16.7	67.0
Less Imputed Interest	61.5	5.8	—	10.4	16.4	3.2	2.5	5.3
Estimated Present Value of Future Minimum Lease Payments	$ 315.4	$ 31.0	$ —	$ 41.9	$ 43.1	$ 18.1	$ 14.2	$ 61.7

Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Year 1	$ 267.5	$ 15.7	$ 2.4	$ 18.4	$ 92.2	$ 16.6	$ 7.4	$ 8.4
Year 2	252.4	15.2	1.5	16.4	88.4	13.9	6.6	8.2
Year 3	239.9	14.1	0.7	14.7	86.3	13.3	6.0	7.5
Year 4	154.2	13.0	0.3	12.5	48.0	12.4	5.5	7.2
Year 5	63.6	11.4	—	9.8	7.3	10.8	5.0	5.0
Later Years	184.1	27.8	—	20.1	22.0	38.3	12.7	12.4
Total Future Minimum Lease Payments	1,161.7	97.2	4.9	91.9	344.2	105.3	43.2	48.7
Less Imputed Interest	131.8	14.4	0.4	11.8	28.2	16.6	6.0	10.3
Estimated Present Value of Future Minimum Lease Payments	$ 1,029.9	$ 82.8	$ 4.5	$ 80.1	$ 316.0	$ 88.7	$ 37.2	$ 38.4

Future minimum lease payments consisted of the following as of December 31, 2018:

Finance Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2019	$ 70.8	$ 5.8	$ 0.1	$ 9.0	$ 8.2	$ 3.3	$ 3.4	$ 13.1
2020	60.2	5.3	—	8.0	7.2	2.7	2.6	11.5
2021	51.7	4.7	—	7.3	6.6	2.3	2.0	10.5
2022	43.8	4.2	—	6.8	6.1	1.7	1.6	9.4
2023	35.5	3.7	—	6.3	5.7	1.2	1.4	8.6
Later Years	90.2	10.1	—	13.3	21.7	2.8	3.3	18.7
Total Future Minimum Lease Payments	352.2	33.8	0.1	50.7	55.5	14.0	14.3	71.8
Less Imputed Interest	63.2	5.3	—	10.9	16.8	1.9	2.0	11.0
Estimated Present Value of Future Minimum Lease Payments	$ 289.0	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 60.8

Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2019	$ 259.6	$ 15.1	$ 2.3	$ 17.6	$ 92.6	$ 14.5	$ 6.5	$ 7.4
2020	250.1	14.1	1.8	16.5	89.3	13.2	6.0	7.2
2021	232.7	13.2	1.0	13.9	84.8	10.9	5.0	6.7
2022	222.5	12.2	0.5	12.8	83.8	10.0	4.6	6.1
2023	58.3	10.8	0.1	9.9	6.5	8.8	4.1	5.0
Later Years	165.2	28.4	—	20.5	19.5	31.7	10.7	11.7
Total Future Minimum Lease Payments	$ 1,188.4	$ 93.8	$ 5.7	$ 91.2	$ 376.5	$ 89.1	$ 36.9	$ 44.1

Master Lease Agreements (Applies to all Registrants except AEPTCo)

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 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 amount guaranteed. As of September 30, 2019, 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 was as follows:

Company	Maximum Potential Loss
	(in millions)
AEP	$ 46.6
AEP Texas	11.2
APCo	6.3
I&M	4.0
OPCo	7.4
PSO	4.3
SWEPCo	4.7

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. In the first quarter of 2019, in accordance with ASU 2016-02, the $37 million unamortized gain ($15 million related to I&M) associated with the sale-and-leaseback of the Plant was recognized as an adjustment to equity. The adjustment to equity was then reclassified to regulatory liabilities in accordance with accounting guidance for "Regulated Operations" as AEGCo and I&M will continue to provide the benefit of the unamortized gain to customers in future periods.

The Owner Trustee owns the Plant and leases equal portions 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 and at the end of the lease term, AEGCo and I&M have the option to renew the lease at a rate that approximates fair value. The option to renew was not included in the measurement of the lease obligation as of September 30, 2019 as the execution of the option was not reasonably certain. 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 September 30, 2019 were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2019	$ 74.2	$ 37.1
2020	147.8	73.9
2021	147.8	73.9
2022	147.2	73.6
Total Future Minimum Lease Payments	$ 517.0	$ 258.5

(a) AEP's future minimum lease payments include equal shares from AEGCo and I&M.

AEPRO Boat and Barge Leases (Applies to AEP)

In 2015, AEP sold its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. Certain 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 2027. As of September 30, 2019, the maximum potential amount of future payments required under the guaranteed leases was $56 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 September 30, 2019, AEP's boat and barge lease guarantee liability was $4 million, of which $1 million was recorded in Other Current Liabilities and $3 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheet.

In January 2018, S&P Global Inc. downgraded the ratings of the nonaffiliated party and set their outlook to negative. In April 2018, Moody's Investors Service Inc. (Moody's) also downgraded their rating and set their outlook to negative. Moody's further downgraded their rating in April 2019 and maintained a negative outlook. It is reasonably possible that enforcement of AEP's liability for future payments under these leases could be exercised, which could reduce future net income and cash flows and impact financial condition.

Lessor Activity

The Registrants' lessor activity was immaterial as of and for the three and nine months ended September 30, 2019.

13. FINANCING ACTIVITIES

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

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding, net of issuance costs and premiums or discounts:

Type of Debt	September 30, 2019	December 31, 2018
	(in millions)	
Senior Unsecured Notes	$ 20,829.2	$ 18,903.3
Pollution Control Bonds	1,516.5	1,643.8
Notes Payable	189.1	204.7
Securitization Bonds	1,059.4	1,111.4
Spent Nuclear Fuel Obligation (a)	278.5	273.6
Junior Subordinated Notes (b)	786.8	—
Other Long-term Debt	1,221.7	1,209.9
Total Long-term Debt Outstanding	25,881.2	23,346.7
Long-term Debt Due Within One Year	1,327.7	1,698.5
Long-term Debt	$ 24,553.5	$ 21,648.2

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for SNF disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $322 million and $317 million as of September 30, 2019 and December 31, 2018, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.
(b) See “Equity Units” section below for additional information.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2019 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
AEP	Junior Subordinated Notes (b)	$ 805.0	3.40	2024
AEP Texas	Securitization Bonds	117.6	2.06	2025
AEP Texas	Securitization Bonds	117.6	2.29	2029
AEP Texas	Pollution Control Bonds	100.6	2.60	2029
AEP Texas	Senior Unsecured Notes	300.0	4.15	2049
AEPTCo	Senior Unsecured Notes	350.0	3.80	2049
AEPTCo	Senior Unsecured Notes	350.0	3.15	2049
APCo	Pollution Control Bonds	86.0	2.55	2024
APCo	Senior Unsecured Notes	400.0	4.50	2049
I&M	Notes Payable	62.8	Variable	2023
OPCo	Senior Unsecured Notes	450.0	4.00	2049
PSO	Senior Unsecured Notes	100.0	3.91	2029
PSO	Senior Unsecured Notes	150.0	4.11	2034
PSO	Senior Unsecured Notes	100.0	4.50	2049
Non-Registrant:				
AEGCo	Pollution Control Bonds	45.0	1.35	2022
Transource Energy	Other Long-term Debt	14.4	Variable	2020
Total Issuances		$ 3,549.0		

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.
(b) See “Equity Units” section below for additional information.

Company	Type of Debt	Principal Amount Paid		Interest Rate	Due Date
Retirements and Principal Payments:		**(in millions)**		**(%)**	
AEP Texas	Senior Unsecured Notes	$	50.0	2.61	2019
AEP Texas	Securitization Bonds		28.2	1.98	2020
AEP Texas	Securitization Bonds		188.0	5.31	2020
AEP Texas	Pollution Control Bonds		100.6	6.30	2029
APCo	Pollution Control Bonds		86.0	1.90	2019
APCo	Pollution Control Bonds		70.0	3.25	2019
APCo	Securitization Bonds		24.4	2.01	2023
I&M	Notes Payable		2.7	Variable	2019
I&M	Notes Payable		4.3	Variable	2019
I&M	Notes Payable		13.7	Variable	2020
I&M	Notes Payable		17.9	Variable	2021
I&M	Notes Payable		11.3	Variable	2022
I&M	Notes Payable		16.0	Variable	2022
I&M	Notes Payable		6.4	Variable	2023
I&M	Other Long-term Debt		1.3	6.00	2025
OPCo	Securitization Bonds		47.9	2.05	2019
OPCo	Other Long-term Debt		0.1	1.15	2028
PSO	Senior Unsecured Notes		250.0	5.15	2019
PSO	Other Long-term Debt		0.4	3.00	2027
SWEPCo	Pollution Control Bonds		53.5	1.60	2019
SWEPCo	Other Long-term Debt		1.5	4.68	2028
SWEPCo	Notes Payable		3.2	4.58	2032
Non-Registrant:					
AEGCo	Pollution Control Bonds		45.0	Variable	2019
AEP Energy	Notes Payable		0.1	5.75	2019
Transource Energy	Other Long-term Debt		1.0	Variable	2020
Total Retirements and Principal Payments		$	1,023.5		

As of September 30, 2019, trustees held, on behalf of AEP, $574 million of their reacquired Pollution Control Bonds. Of this total, $345 million relates to OPCo.

Long-term Debt Subsequent Events

In October 2019, AEP remarketed $240 million of Pollution Control Bonds that were held in trust.

In October 2019, I&M retired $4 million of Notes Payable related to DCC Fuel.

In October 2019, I&M retired $25 million of variable rate Pollution Control Bonds.

Equity Units (Applies to AEP)

In March 2019, AEP issued 16.1 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $805 million. Net proceeds from the issuance were approximately $785 million. The proceeds were used to support AEP's overall capital expenditure plans including the recent acquisition of Sempra Renewables LLC.

Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 3.40% Junior Subordinated Notes (notes) due in 2024 and a forward equity purchase contract which settles after three years in 2022. The notes are expected to be remarketed in 2022, at which time the interest rate will reset at the then current market rate. Investors may choose to remarket their notes to receive the remarketing proceeds and use those funds to settle the forward equity purchase contract, or accept the remarketed debt and use other funds for the equity purchase. If the remarketing is unsuccessful, investors have the right to put their notes to AEP at a price equal to the

principal. The Equity Units carry an annual distribution rate of 6.125%, which is comprised of a quarterly coupon rate of interest of 3.40% and a quarterly forward equity purchase contract payment of 2.725%.

Each forward equity purchase contract obligates the holder to purchase, and AEP to sell, for $50 a number of shares in common stock in accordance with the conversion ratios set forth below (subject to an anti-dilution adjustment):

- If the AEP common stock market price is equal to or greater than $99.58: 0.5021 shares per contract.
- If the AEP common stock market price is less than $99.58 but greater than $82.98: a number of shares per contract equal to $50 divided by the applicable market price. The holder receives a variable number of shares at $50.
- If the AEP common stock market price is less than or equal to $82.98: 0.6026 shares per contract.

A holder's ownership interest in the notes is pledged to AEP to secure the holder's obligation under the related forward equity purchase contract. If a holder of the forward equity purchase contract chooses at any time to no longer be a holder of the notes, such holder's obligation under the forward equity purchase contract must be secured by a U.S. Treasury security which must be equal to the aggregate principal amount of the notes.

At the time of issuance, the $805 million of notes were recorded within Long-term Debt on the balance sheets. The present value of the purchase contract payments of $62 million were recorded in Deferred Credits and Other Noncurrent Liabilities with a current portion in Other Current Liabilities at the time of issuance, representing the obligation to make forward equity contract payments, with an offsetting reduction to Paid-in Capital. The difference between the face value and present value of the purchase contract payments will be accreted to Interest Expense on the statements of income over the three year period ending in 2022. The liability recorded for the contract payments is considered non-cash and excluded from the statements of cash flows. Until settlement of the forward equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method. The maximum amount of shares AEP will be required to issue to settle the purchase contract is 9,701,860 shares (subject to an anti-dilution adjustment).

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. AEPTCo's contractually-defined priority debt was 0.1% of consolidated tangible net assets as of September 30, 2019. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreements.

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. However, 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 have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings.

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 method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

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; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of September 30, 2019 and December 31, 2018 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' activity and corresponding authorized borrowing limits for the nine months ended September 30, 2019 are described in the following table:

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 September 30, 2019	Authorized Short-term Borrowing Limit	
				(in millions)			
AEP Texas	$ 390.7	$ —	$ 261.8	$ —	$ (74.8)	$ 500.0	
AEPTCo	374.9	244.4	179.8	40.2	236.6	795.0	(a)
APCo	225.4	232.2	90.4	61.8	(17.7)	600.0	
I&M	120.4	66.0	53.1	17.2	(89.2)	500.0	
OPCo	291.2	178.6	163.5	50.1	(17.6)	500.0	
PSO	140.5	215.6	63.9	84.1	95.1	300.0	
SWEPCo	105.1	81.4	57.8	11.2	6.4	350.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above table does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of September 30, 2019 and December 31, 2018 are included in Advances to Affiliates on the subsidiaries' balance sheets. The Nonutility Money Pool participants' activity for the nine months ended September 30, 2019 is described in the following table:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of September 30, 2019
		(in millions)	
AEP Texas	$ 8.0	$ 7.7	$ 7.7
SWEPCo	2.1	2.0	2.1

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of outstanding loans to and borrowings from AEP as of September 30, 2019 and December 31, 2018 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets. AEPTCo's direct borrowing and lending activity with AEP and corresponding authorized borrowing limit for the nine months ended September 30, 2019 are described in the following table:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of September 30, 2019	Loans to AEP as of September 30, 2019	Authorized Short-term Borrowing Limit	
				(in millions)			
$ 1.3	$ 117.6	$ 1.3	$ 63.4	$ 1.3	$ 30.8	$ 75.0	(a)

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Nine Months Ended September 30, 2019	2018
Maximum Interest Rate	3.43%	2.52%
Minimum Interest Rate	1.83%	1.81%

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:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Nine Months Ended September 30, 2019	2018	Average Interest Rate for Funds Loaned to the Utility Money Pool for Nine Months Ended September 30, 2019	2018
AEP Texas	2.71%	2.25%	—%	2.29%
AEPTCo	2.72%	2.26%	2.57%	2.04%
APCo	2.82%	2.22%	2.73%	2.19%
I&M	2.56%	2.16%	2.73%	2.06%
OPCo	2.80%	2.18%	2.68%	2.47%
PSO	2.85%	2.25%	2.48%	1.86%
SWEPCo	2.74%	2.31%	2.47%	1.87%

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool are summarized in the following table:

	Nine Months Ended September 30, 2019			Nine Months Ended September 30, 2018		
Company	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	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
AEP Texas	3.02%	2.36%	2.70%	2.52%	1.83%	2.26%
SWEPCo	3.02%	2.36%	2.70%	2.52%	1.83%	2.26%

AEPTCo's maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following table:

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
2019	3.02%	2.36%	3.02%	2.36%	2.70%	2.70%
2018	2.52%	1.76%	2.52%	1.76%	2.26%	2.27%

Short-term Debt (Applies to AEP)

Outstanding short-term debt was as follows:

Type of Debt	September 30, 2019		December 31, 2018	
	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
	(dollars in millions)			
Securitized Debt for Receivables (b)	$ 750.0	2.56%	$ 750.0	2.16%
Commercial Paper	1,760.0	2.36%	1,160.0	2.96%
Total Short-term Debt	$ 2,510.0		$ 1,910.0	

(a) Weighted-average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement that provides a commitment of $750 million from bank conduits to purchase receivables and expires in July 2021. 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. Accounts receivable information for AEP Credit was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	2.37%	2.27%	2.56%	2.06%
Net Uncollectible Accounts Receivable Written-Off	$ 8.8	$ 9.6	$ 19.8	$ 19.0

	September 30, 2019	December 31, 2018
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 923.3	$ 972.5
Short-term – Securitized Debt of Receivables	750.0	750.0
Delinquent Securitized Accounts Receivable	43.9	50.3
Bad Debt Reserves Related to Securitization	32.3	27.5
Unbilled Receivables Related to Securitization	216.2	281.4

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to Registrant Subsidiaries, except AEP Texas and AEPTCo)

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 agreements were:

Company	September 30, 2019	December 31, 2018
	(in millions)	
APCo	$ 95.4	$ 133.3
I&M	156.2	152.9
OPCo	337.5	395.2
PSO	149.4	109.7
SWEPCo	168.6	150.3

The fees paid to AEP Credit for customer accounts receivable sold were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2019	2018	2019	2018
	(in millions)			
APCo	$ 1.2	$ 1.8	$ 5.8	$ 5.1
I&M	2.4	2.5	8.4	6.8
OPCo	6.4	7.2	22.1	18.8
PSO	2.0	2.3	6.2	6.0
SWEPCo	1.9	2.6	7.9	6.6

The proceeds on the sale of receivables to AEP Credit were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2019	2018	2019	2018
	(in millions)			
APCo	$ 303.3	$ 334.1	$ 978.5	$ 1,079.2
I&M	485.3	498.4	1,378.9	1,401.7
OPCo	602.6	695.2	1,746.1	2,046.9
PSO	451.5	454.9	1,118.7	1,171.2
SWEPCo	480.7	512.6	1,247.0	1,364.6

14. VARIABLE INTEREST ENTITIES AND EQUITY METHOD INVESTMENTS

The disclosures in this note apply to AEP only 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 holds ownership interests in businesses with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE, and if so, whether or not the VIE should be consolidated into AEP's financial statements. If an entity is determined not to be a VIE, or if the entity is determined to be a VIE and AEP is not deemed to be the primary beneficiary, the entity is accounted for under the equity method of accounting. The Variable Interest Entities note within the 2018 Annual Report should be read in conjunction with this report as this note only includes significant changes to AEP's VIEs and equity method investments during 2019.

Consolidated Variable Interests Entities

Restoration Funding (Applies to AEP and AEP Texas)

Restoration Funding was formed for the sole purpose of issuing and servicing securitization bonds related to storm restoration of AEP Texas' distribution system primarily due to damage caused by Hurricane Harvey. See "Texas Storm Cost Securitization" section of Note 4 for additional information. Management has concluded that AEP Texas is the primary beneficiary of Restoration 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 Restoration Funding. The securitized bonds totaled $235 million as of September 30, 2019 and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Restoration Funding has securitized assets of $235 million as of September 30, 2019 which are presented separately on the face of the balance sheets. The securitized restoration assets represent the right to impose and collect Texas storm restoration 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 assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Restoration Fundings' securitized assets and remits all related amounts collected from customers to Restoration Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Restoration Fundings' assets and liabilities on the balance sheets.

Apple Blossom Wind Holdings LLC and Black Oak Getty Wind Holdings LLC

In April 2019, AEP acquired an equity interest in Apple Blossom Wind Holdings LLC (Apple Blossom) and Black Oak Getty Wind Holdings LLC (Black Oak) (the Project Entities) as part of the purchase of Sempra Renewables LLC. Both of the Project Entities have long-term PPAs for 100% of their energy production. The Project Entities are tax equity partnerships with nonaffiliated noncontrolling interests to which a percentage of earnings, tax attributes and cash flows are allocated in accordance with the respective limited liability company agreements. Management has concluded that the Project Entities are VIEs and that AEP is the primary beneficiary based on its power as managing member to direct the activities that most significantly impact the Project Entities' economic performance. In addition, AEP has not provided material financial or other support to the Project Entities that was not previously contractually required. As the primary beneficiary of the Project Entities, AEP consolidates the Project Entities into its financial statements. See the table below for the classification of Project Entities' assets and liabilities on the balance sheets.

The nonaffiliated interests in the Project Entities is presented in Noncontrolling Interests on the balance sheets. As of September 30, 2019, AEP recorded $129 million of Noncontrolling Interests related to the Project Entities in Equity on the balance sheets.

The Project Entities' tax equity partnerships represent substantive profit-sharing arrangements. The method for attributing income and loss to the noncontrolling interests is a balance sheet approach referred to as the hypothetical liquidation at book value (HLBV) method. Under the HLBV method, the income and loss attributable to the noncontrolling interests reflect changes in the amounts the members would hypothetically receive at each balance sheet date under the liquidation provisions of the respective limited liability company agreements, assuming the net assets of these entities were liquidated at recorded amounts, after taking into account any capital transactions, such as contributions or distributions, between the entities and the members. For the three and nine months ended September 30, 2019, the HLBV method resulted in $0 and a loss of $4 million, respectively, allocated to Noncontrolling Interests.

Santa Rita East

In July 2019, AEP acquired a 75% interest in Santa Rita East Wind Energy Holdings, LLC and its wholly-owned subsidiary, Santa Rita East Wind Energy, LLC (collectively, Santa Rita East). Santa Rita East is a partnership whose sole purpose is to own and operate a new 302.4 MW wind generation facility in west Texas. Santa Rita East delivers energy and provides renewable energy credits through three long-term PPAs totaling 260 MWs. The remaining 42.4 MWs of energy are sold at wholesale into ERCOT. Management has concluded that Santa Rita East is a VIE and that AEP is the primary beneficiary based on its power as managing member of the partnership to direct the activities that most significantly impact Santa Rita East's economic performance. As the primary beneficiary of Santa Rita East, AEP consolidates Santa Rita East into its financial statements. See the table below for the classification of Santa Rita's assets and liabilities on the balance sheets.

AEP recognized $8 million of PTC attributable to Santa Rita East for the three and nine months ended September 30, 2019 which was recorded in Income Tax Expense (Benefit) on the statements of income. The nonaffiliated interest in Santa Rita East is presented in Noncontrolling Interests on the balance sheets. As of September 30, 2019, AEP recorded $118 million of Noncontrolling Interests related to Santa Rita East in Equity on the balance sheets.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
September 30, 2019

	Registrant Subsidiary	Other Consolidated VIEs	
	AEP Texas Restoration Funding	Apple Blossom and Black Oak	Santa Rita East
	(in millions)		
ASSETS			
Current Assets	$ 1.2	$ 5.7	$ 17.0
Net Property, Plant and Equipment	—	233.3	466.6
Other Noncurrent Assets	235.3	12.5	0.8
Total Assets	$ 236.5	$ 251.5	$ 484.4
LIABILITIES AND EQUITY			
Current Liabilities	$ 14.4	$ 2.2	$ 3.5
Noncurrent Liabilities	220.9	4.6	7.5
Equity	1.2	244.7	473.4
Total Liabilities and Equity	$ 236.5	$ 251.5	$ 484.4

Significant Equity Method Investments in Unconsolidated Entities

The equity method of accounting is used for equity investments where AEP exercises significant influence but does 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 or losses is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. AEP regularly monitors and evaluates equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

Sempra Renewables LLC

In April 2019, AEP acquired a 50% interest in five wind farms in multiple states as part of the purchase of Sempra Renewables LLC. The wind farms are joint ventures with BP Wind Energy who holds the other 50% interest. All five wind farms have long-term PPAs for 100% of their energy production. One of the jointly-owned wind farms has PPAs with I&M and OPCo for a portion of its energy production. Another jointly-owned wind farm has a PPA with SWEPCo for a portion of its energy production. The joint venture wind farms are not considered VIEs and AEP is not required to consolidate them as AEP does not have a controlling financial interest. However, AEP is able to exercise significant influence over the wind farms and therefore applies the equity method of accounting. As of September 30, 2019, AEP's investment in the five joint venture wind farms was $389 million. The investment includes amounts recognized in AOCI related to interest rate cash flow hedges. The investment is comprised of a historical investment of $417 million plus a basis difference of $(19) million. AEP's equity earnings associated with the five joint venture wind farms were losses of $3 million and $6 million for the three and nine months ended September 30, 2019, respectively. AEP recognized $7 million and $21 million of PTC attributable to the joint venture wind farms for the three and nine months ended September 30, 2019, respectively, which was recorded in Income Tax Expense (Benefit) on the statements of income.

ETT

ETT designs, acquires, constructs, owns and operates certain transmission facilities in ERCOT. Berkshire Hathaway Energy, a nonaffiliated entity, holds a 50% membership interest in ETT, AEP Transmission Holdco holds a 49.5% interest in ETT and AEP Transmission Partner held the remaining 0.5% membership interest in ETT. In July 2019, AEP Transmission Partner was merged into AEP Transmission Holdco, increasing AEP Transmission Holdco's interest in ETT to 50%. As a result, AEP, through its wholly-owned subsidiary, holds a 50% membership interest in ETT. As of September 30, 2019 and December 31, 2018, AEP's investment in ETT was $693 million and $666 million, respectively. AEP's equity earnings associated with ETT were $16 million and $15 million for the three months ended September 30, 2019 and 2018, respectively. AEP's equity earnings associated with ETT were $49 million and $46 million for the nine months ended September 30, 2019 and 2018, respectively.

15. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The tables below represent AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Three Months Ended September 30, 2019						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,060.2	$ 588.0	$ —	$ —	$ —	$ —	$ 1,648.2
Commercial Revenues	612.5	290.9	—	—	—	—	903.4
Industrial Revenues	566.0	99.3	—	—	—	1.5	666.8
Other Retail Revenues	49.2	10.6	—	—	—	—	59.8
Total Retail Revenues	2,287.9	988.8	—	—	—	1.5	3,278.2
Wholesale and Competitive Retail Revenues:							
Generation Revenues (a)	231.3	—	—	77.1	—	(34.2)	274.2
Transmission Revenues (b)	77.8	110.9	269.4	—	—	(217.2)	240.9
Marketing, Competitive Retail and Renewable Revenues	—	—	—	415.4	—	0.5	415.9
Total Wholesale and Competitive Retail Revenues	309.1	110.9	269.4	492.5	—	(250.9)	931.0
Other Revenues from Contracts with Customers (c)	47.3	42.9	4.5	14.8	35.6	(42.2)	102.9
Total Revenues from Contracts with Customers	2,644.3	1,142.6	273.9	507.3	35.6	(291.6)	4,312.1
Other Revenues:							
Alternative Revenues (c)	1.2	5.1	(0.9)	—	—	(16.8)	(11.4)
Other Revenues (c)	—	38.9	—	26.4	(11.2)	(39.8)	14.3
Total Other Revenues	1.2	44.0	(0.9)	26.4	(11.2)	(56.6)	2.9
Total Revenues	$ 2,645.5	$ 1,186.6	$ 273.0	$ 533.7	$ 24.4	$ (348.2)	$ 4,315.0

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $34 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $197 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues.

	Three Months Ended September 30, 2018						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 1,048.7	$ 612.2	$ —	$ —	$ —	$ —	$ 1,660.9
Commercial Revenues	612.8	330.9	—	—	—	—	943.7
Industrial Revenues	578.8	128.8	—	—	—	—	707.6
Other Retail Revenues	49.1	10.7	—	—	—	—	59.8
Total Retail Revenues (a)	2,289.4	1,082.6	—	—	—	—	3,372.0
Wholesale and Competitive Retail Revenues:							
Generation Revenues (b)	224.2	—	—	115.1	—	(98.5)	240.8
Transmission Revenues (c)	72.8	88.0	201.4	—	—	(241.6)	120.6
Marketing, Competitive Retail and Renewable Revenues	—	—	—	399.1	—	—	399.1
Total Wholesale and Competitive Retail Revenues	297.0	88.0	201.4	514.2	—	(340.1)	760.5
Other Revenues from Contracts with Customers (e)	40.3	69.9	0.7	12.7	21.5	49.5	194.6
Total Revenues from Contracts with Customers	2,626.7	1,240.5	202.1	526.9	21.5	(290.6)	4,327.1
Other Revenues:							
Alternative Revenues (d)	0.2	(37.9)	(14.9)	—	—	—	(52.6)
Other Revenues (e)	9.8	8.9	—	(5.3)	2.2	43.0	58.6
Total Other Revenues	10.0	(29.0)	(14.9)	(5.3)	2.2	43.0	6.0
Total Revenues	$ 2,636.7	$ 1,211.5	$ 187.2	$ 521.6	$ 23.7	$ (247.6)	$ 4,333.1

(a) 2018 amounts have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $35 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $147 million. The remaining affiliated amounts were immaterial.
(d) The alternative revenue for Transmission and Distribution Utilities was primarily the $48 million reduction in revenue relating to the Ohio Tax Reform settlement.
(e) Amounts include affiliated and nonaffiliated revenues.

	Three Months Ended September 30, 2019						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 192.0	$ —	$ 315.7	$ 198.2	$ 395.6	$ 231.9	$ 222.9
Commercial Revenues	110.6	—	147.2	138.3	180.5	122.2	144.3
Industrial Revenues	32.2	—	152.2	138.7	67.1	84.1	92.3
Other Retail Revenues	7.5	—	18.5	1.9	3.1	24.9	2.3
Total Retail Revenues	342.3	—	633.6	477.1	646.3	463.1	461.8
Wholesale Revenues:							
Generation Revenues (a)	—	—	70.4	102.1	—	21.1	50.7
Transmission Revenues (b)	97.7	256.4	26.2	6.4	13.7	(3.4)	30.0
Total Wholesale Revenues	97.7	256.4	96.6	108.5	13.7	17.7	80.7
Other Revenues from Contracts with Customers (c)	8.2	4.5	18.7	26.6	41.0	5.1	7.0
Total Revenues from Contracts with Customers	448.2	260.9	748.9	612.2	701.0	485.9	549.5
Other Revenues:							
Alternative Revenues (d)	(0.7)	(1.2)	6.6	(1.1)	12.4	7.1	(4.0)
Other Revenues (d)	41.8	—	—	—	(2.8)	—	—
Total Other Revenues	41.1	(1.2)	6.6	(1.1)	9.6	7.1	(4.0)
Total Revenues	$ 489.3	$ 259.7	$ 755.5	$ 611.1	$ 710.6	$ 493.0	$ 545.5

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $32 million primarily relating to the PPA with Kingsport. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $194 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $20 million primarily relating to the barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Three Months Ended September 30, 2018						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 178.8	$ —	$ 320.9	$ 207.4	$ 433.5	$ 220.8	$ 214.1
Commercial Revenues	107.9	—	155.1	138.0	222.9	119.9	140.4
Industrial Revenues	32.1	—	157.6	150.2	96.3	82.4	89.6
Other Retail Revenues	7.4	—	19.2	1.7	3.3	24.5	2.2
Total Retail Revenues (a)	326.2	—	652.8	497.3	756.0	447.6	446.3
Wholesale Revenues:							
Generation Revenues (b)	—	—	74.5	93.6	—	12.5	53.2
Transmission Revenues (c)	73.6	206.6	20.9	6.2	14.8	13.5	29.5
Total Wholesale Revenues	73.6	206.6	95.4	99.8	14.8	26.0	82.7
Other Revenues from Contracts with Customers (d)	7.5	0.2	15.9	22.4	(29.9)	5.5	6.6
Total Revenues from Contracts with Customers	407.3	206.8	764.1	619.5	740.9	479.1	535.6
Other Revenues:							
Alternative Revenues (e)	(1.0)	(12.4)	(1.2)	1.5	(36.9)	2.3	(0.3)
Other Revenues (f)	27.1	—	(0.9)	8.7	74.3	—	—
Total Other Revenues	26.1	(12.4)	(2.1)	10.2	37.4	2.3	(0.3)
Total Revenues	$ 433.4	$ 194.4	$ 762.0	$ 629.7	$ 778.3	$ 481.4	$ 535.3

(a) 2018 amounts have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $30 million primarily relating to the PPA with Kingsport. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $146 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $17 million primarily relating to the barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(e) The alternative revenue for OPCo was primarily the $48 million reduction in revenue relating to the Ohio Tax Reform settlement.
(f) Amounts include affiliated and nonaffiliated revenues.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	Nine Months Ended September 30, 2019						
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 2,797.6	$ 1,609.1	$ —	$ —	$ —	$ —	$ 4,406.7
Commercial Revenues	1,641.2	889.4	—	—	—	—	2,530.6
Industrial Revenues	1,647.3	332.6	—	—	—	—	1,979.9
Other Retail Revenues	136.1	32.8	—	—	—	—	168.9
Total Retail Revenues	6,222.2	2,863.9	—	—	—	—	9,086.1
Wholesale and Competitive Retail Revenues:							
Generation Revenues (a)	661.9	—	—	282.0	—	(105.5)	838.4
Transmission Revenues (b)	215.4	324.0	814.3	—	—	(603.6)	750.1
Marketing, Competitive Retail and Renewable Revenues	—	—	—	1,088.5	—	0.5	1,089.0
Total Wholesale and Competitive Retail Revenues	877.3	324.0	814.3	1,370.5	—	(708.6)	2,677.5
Other Revenues from Contracts with Customers (c)	128.8	127.6	12.6	4.5	80.4	(113.6)	240.3
Total Revenues from Contracts with Customers	7,228.3	3,315.5	826.9	1,375.0	80.4	(822.2)	12,003.9
Other Revenues:							
Alternative Revenues (c)	(55.7)	21.5	(18.6)	—	—	(60.3)	(113.1)
Other Revenues (c)	—	117.3	—	53.2	(6.7)	(109.2)	54.6
Total Other Revenues	(55.7)	138.8	(18.6)	53.2	(6.7)	(169.5)	(58.5)
Total Revenues	$ 7,172.6	$ 3,454.3	$ 808.3	$ 1,428.2	$ 73.7	$ (991.7)	$ 11,945.4

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $105 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $596 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues.

	Nine Months Ended September 30, 2018						
	Vertically Integrated Utilities	**Transmission and Distribution Utilities**	**AEP Transmission Holdco**	**Generation & Marketing**	**Corporate and Other**	**Reconciling Adjustments**	**AEP Consolidated**
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 2,906.9	$ 1,711.1	$ —	$ —	$ —	$ —	$ 4,618.0
Commercial Revenues	1,672.7	945.2	—	—	—	—	2,617.9
Industrial Revenues	1,676.1	381.5	—	—	—	—	2,057.6
Other Retail Revenues	139.4	31.8	—	—	—	—	171.2
Total Retail Revenues (a)	6,395.1	3,069.6	—	—	—	—	9,464.7
Wholesale and Competitive Retail Revenues:							
Generation Revenues (b)	686.5	—	—	413.4	—	(155.2)	944.7
Transmission Revenues (c)	208.4	272.6	633.9	—	—	(520.7)	594.2
Marketing, Competitive Retail and Renewable Revenues	—	—	—	1,040.2	—	—	1,040.2
Total Wholesale and Competitive Retail Revenues	894.9	272.6	633.9	1,453.6	—	(675.9)	2,579.1
Other Revenues from Contracts with Customers (e)	121.8	165.1	11.1	15.0	64.8	1.8	379.6
Total Revenues from Contracts with Customers	7,411.8	3,507.3	645.0	1,468.6	64.8	(674.1)	12,423.4
Other Revenues:							
Alternative Revenues (d)	(19.2)	(48.3)	(39.8)	—	—	—	(107.3)
Other Revenues (e)	1.1	51.9	—	18.8	6.7	—	78.5
Total Other Revenues	(18.1)	3.6	(39.8)	18.8	6.7	—	(28.8)
Total Revenues	$ 7,393.7	$ 3,510.9	$ 605.2	$ 1,487.4	$ 71.5	$ (674.1)	$ 12,394.6

(a) 2018 amounts have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $87 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $444 million. The remaining affiliated amounts were immaterial.
(d) The alternative revenue for Transmission and Distribution Utilities was primarily the $48 million reduction in revenue relating to the Ohio Tax Reform settlement.
(e) Amounts include affiliated and nonaffiliated revenues.

	Nine Months Ended September 30, 2019						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 454.9	$ —	$ 944.7	$ 558.8	$ 1,155.5	$ 519.6	$ 503.7
Commercial Revenues	314.5	—	421.5	371.4	573.7	304.3	371.1
Industrial Revenues	98.8	—	444.3	411.9	233.9	238.1	257.2
Other Retail Revenues	22.7	—	56.5	5.4	9.8	63.1	6.7
Total Retail Revenues	890.9	—	1,867.0	1,347.5	1,972.9	1,125.1	1,138.7
Wholesale Revenues:							
Generation Revenues (a)	—	—	200.1	327.4	—	35.5	152.7
Transmission Revenues (b)	282.0	775.3	77.6	18.8	42.0	21.9	78.0
Total Wholesale Revenues	282.0	775.3	277.7	346.2	42.0	57.4	230.7
Other Revenues from Contracts with Customers (c)	22.9	12.6	48.2	76.2	113.3	16.7	20.1
Total Revenues from Contracts with Customers	1,195.8	787.9	2,192.9	1,769.9	2,128.2	1,199.2	1,389.5
Other Revenues:							
Alternative Revenues (d)	(0.4)	(17.8)	11.2	(1.4)	22.0	(25.3)	(47.4)
Other Revenues (d)	122.6	—	—	—	3.8	—	—
Total Other Revenues	122.2	(17.8)	11.2	(1.4)	25.8	(25.3)	(47.4)
Total Revenues	$ 1,318.0	$ 770.1	$ 2,204.1	$ 1,768.5	$ 2,154.0	$ 1,173.9	$ 1,342.1

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $96 million primarily relating to the PPA with Kingsport. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $587 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $57 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Nine Months Ended September 30, 2018						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 453.6	$ —	$ 1,017.3	$ 559.4	$ 1,258.4	$ 531.4	$ 512.4
Commercial Revenues	310.8	—	442.3	369.8	633.2	309.3	372.6
Industrial Revenues	94.8	—	457.3	428.0	287.4	228.7	254.0
Other Retail Revenues	21.7	—	57.6	5.4	9.8	65.2	6.4
Total Retail Revenues (a)	880.9	—	1,974.5	1,362.6	2,188.8	1,134.6	1,145.4
Wholesale Revenues:							
Generation Revenues (b)	—	—	194.1	349.7	—	26.7	168.8
Transmission Revenues (c)	229.6	612.9	60.2	16.9	42.8	29.4	77.3
Total Wholesale Revenues	229.6	612.9	254.3	366.6	42.8	56.1	246.1
Other Revenues from Contracts with Customers (d)	21.8	8.7	42.2	71.0	51.3	14.6	18.0
Total Revenues from Contracts with Customers	1,132.3	621.6	2,271.0	1,800.2	2,282.9	1,205.3	1,409.5
Other Revenues:							
Alternative Revenues (e)	(1.1)	(35.4)	(20.7)	(4.0)	(47.2)	11.2	2.3
Other Revenues (f)	62.1	—	(0.9)	—	82.3	—	—
Total Other Revenues	61.0	(35.4)	(21.6)	(4.0)	35.1	11.2	2.3
Total Revenues	$ 1,193.3	$ 586.2	$ 2,249.4	$ 1,796.2	$ 2,318.0	$ 1,216.5	$ 1,411.8

(a) 2018 amounts have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $100 million primarily relating to the PPA with Kingsport. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $448 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $57 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(e) The alternative revenue for OPCo was primarily the $48 million reduction in revenue relating to the Ohio Tax Reform settlement.
(f) Amounts include affiliated and nonaffiliated revenues.

Fixed Performance Obligations

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of September 30, 2019. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The Registrant Subsidiaries amounts shown in the table below include affiliated and nonaffiliated revenues.

Company	2019	2020-2021	2022-2023	After 2023	Total
			(in millions)		
AEP	$ 252.7	$ 209.7	$ 160.9	$ 285.5	$ 908.8
AEP Texas	96.8	—	—	—	96.8
AEPTCo	225.8	—	—	—	225.8
APCo	36.4	32.5	25.5	11.6	106.0
I&M	7.2	8.9	8.8	4.4	29.3
OPCo	17.8	7.5	—	—	25.3
PSO	4.3	—	—	—	4.3
SWEPCo	9.8	—	—	—	9.8

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have material contract assets as of September 30, 2019 and December 31, 2018.

When the Registrants receive consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have material contract liabilities as of September 30, 2019 and December 31, 2018.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrants' balance sheets within the Accounts Receivable - Customers line item. The Registrants' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of September 30, 2019 and December 31, 2018. See "Securitized Accounts Receivable - AEP Credit" section of Note 13 for additional information related to AEP Credit's securitized accounts receivable.

The following table represents the amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on the Registrant Subsidiaries' balance sheets:

Company	September 30, 2019	December 31, 2018
	(in millions)	
AEPTCo	$ 69.9	$ 58.6
APCo	41.4	52.5
I&M	28.0	35.3
OPCo	29.2	46.1
PSO	10.3	12.4
SWEPCo	17.8	16.3

CONTROLS AND PROCEDURES

During the third quarter of 2019, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of September 30, 2019, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

The only change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2019 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting, relates to the Registrants' conversion of work management, asset management, and source to settle (procurement, supply chain, and accounts payable) business processes to a newly implemented third-party software solution. In connection with this conversion, management will continue to evaluate and monitor the Registrants' internal controls over financial reporting to ensure controls remain effective. There were no other changes in the Registrants' internal control over financial reporting during the quarter ended September 30, 2019, that have materially affected, or are reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see "Commitments, Guarantees and Contingencies," of Note 5 incorporated herein by reference.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2018 includes a detailed discussion of risk factors. As of September 30, 2019, there have been no material changes to the risk factors previously disclosed in the 2018 Annual Report on Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 "Mine Safety Disclosure Exhibit" contains the notices of violation and proposed assessments received by DHLC under the Mine Act for the quarter ended September 30, 2019.

Item 5. Other Information

None

Item 6. Exhibits

The documents designated with an (*) below have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof.

Exhibit	Description	Previously Filed as Exhibit to:
AEPTCo‡ File No. 333-217143		
*4.3	Company Order and Officer's Certificate, between AEP Transmission Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee, dated September 11, 2019, establishing the terms of the Series L Notes	Form 8-K Exhibit 4(a) dated September 9, 2019

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
10.1	AEP System Incentive Compensation Deferral Plan Amended and Restated effective June 1, 2019	X							
10.2	AEP Aircraft Timesharing Agreement dated October 1, 2019 between American Electric Power Service Corporation and Nicholas K. Akins	X							
31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
95	Mine Safety Disclosures								X
101.INS	XBRL Instance Document	The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.							
101.SCH	XBRL Taxonomy Extension Schema	X	X	X	X	X	X	X	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X	X	X	X	X	X	X	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase	X	X	X	X	X	X	X	X
101.LAB	XBRL Taxonomy Extension Label Linkbase	X	X	X	X	X	X	X	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	X	X	X	X	X	X	X	X
104	Cover Page Interactive Data File	Formatted as Inline XBRL and contained in Exhibit 101.							

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

AEP TEXAS INC.
AEP TRANSMISSION COMPANY, LLC
APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: October 24, 2019

Exhibit 10.1

AMERICAN ELECTRIC POWER SYSTEM INCENTIVE COMPENSATION DEFERRAL PLAN

(As Amended and Restated Effective June 1, 2019)

ARTICLE I

PURPOSE AND EFFECTIVE DATE

1.1 The American Electric Power System Incentive Compensation Deferral Plan (the "Plan") was established by American Electric Power Service Corporation and such subsidiaries and affiliates designated by the Company for participation in the Plan ("AEP") to allow Eligible Employees to elect to defer receipt of all or a portion of their Incentive Compensation until after their termination of employment.

1.2 The Plan was most recently amended and restated effective January 1, 2008 pursuant to a document that was signed on December 31, 2008. The Plan is now amended and restated again, effective June 1, 2019. Except as otherwise specifically provided herein, the effective date of the Plan, as amended and restated by this document, is June 1, 2019. This amended and restated Plan continues to apply to all deferrals of compensation made under the Plan, unless specifically provided otherwise herein.

ARTICLE II

DEFINITIONS

2.1 "Account" means the separate memo account established and maintained by the Company or the record keeper employed by the Company to record Participant deferrals of Incentive Compensation and to record any related Investment Income on any Stock Units and on the Fund or Funds selected by the Participant or Former Participant. The portion of the Account attributable to Incentive Compensation earned and vested prior to January 1, 2005 (excluding, for this purpose Incentive Compensation attributable to 2004 that was subject to discretionary adjustment and first available for payment subsequent to December 31, 2004) shall be referred to as the Participant's "Legacy Account Balance." The portion of the Account attributable to Incentive Compensation other than that described in the immediately preceding sentence shall be referred to as the Participant's "Active Account Balance."

2.2 "Applicable Tax Payments" means the following types of taxes that AEP may withhold and pay that are described as follows:

(a) Federal Insurance Contributions Act (FICA) tax imposed under Code Sections 3101, 3121(a) and 3121(v)(2) that apply to an amount deferred under the Plan before the amount is paid or made available to the Participant (the "FICA Amount");

(b) State, local, or foreign tax obligations arising from participation in the Plan that apply to an amount deferred under the Plan before the amount is paid or made available to the Participant (the “State, Local, or Foreign Tax Amount”);

(c) Income tax at source on wages imposed under Code Section 3401 or the corresponding withholding provisions of applicable state, local and foreign tax laws as a result of the payment of the FICA Amount or the State, Local, or Foreign Tax Amount; and

(d) The additional income tax at source on wages attributable to pyramiding Code Section 3401 wages and taxes; provided, however, that the total Applicable Tax Payments may not exceed such limits as may be applicable to comply with the requirements of Code Section 409A.

2.3 “Base Compensation” means an employee’s regular annual base salary or wage rate determined without regard to any salary or wage reductions made pursuant to sections 125 or 402(e)(3) of the Code or participant contributions pursuant to a pay reduction agreement under the American Electric Power System Supplemental Retirement Savings Plan, as amended.

2.4 “Claims Reviewer” means the person or committee designated by American Electric Power Service Corporation (or by a duly authorized person) as responsible for the review of claims for benefits under the Plan in accordance with Section 8.1. Until changed, the Claims Reviewer shall be the Director - Compensation and Executive Benefits.

2.5 “Code” means the Internal Revenue Code of 1986 as amended from time to time.

2.6 “Committee” means the committee designated by the American Electric Power Service Corporation (or by a duly authorized person) as responsible for the administration of the Plan. Until changed, the Committee shall consist of the employees of the Company holding the following positions (or a successor position that encompasses the described function): top Human Resources officer; the Chief Administrative Officer and the Chief Financial Officer of the Company. The Committee may authorize any person or persons to act on its behalf with full authority in regard to any of its duties hereunder other than those set forth in Section 8.2.

2.7 “Company” means American Electric Power Service Corporation.

2.8 “Eligible Employee” means any employee of AEP who is designated by the Company as eligible to participate in this Plan. Individuals not directly compensated by AEP or who are not treated by AEP as an active employee shall not be considered Eligible Employees.

2.9 “Executive Officer” means a Participant who, with respect to AEP, is subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934, as amended.

2.10 “First Date Available” or “FDA” means (a) with respect to Key Employees, the last day of the month coincident with or next following the date that is six (6) months after the date of the Participant’s or Former Participant’s Termination; and (b) with respect to all other Participants and Former Participants, the last day of the month coincident with or next following the date that is one (1) month after the date of the Participant’s Termination; provided, however, that the FDA with respect to an Executive Officer shall be no earlier than the December 31of the calendar year of such Executive Officer’s Termination.

2.11 “Former Participant” means a Participant whose employment with AEP has terminated or a Participant who is no longer an Eligible Employee, but whose Account has a balance greater than zero.

2.12 “Fund” means the core investment options made available to participants in the AEP Retirement Savings 401k Plan, as revised from time to time, except as the Committee may specify otherwise. The investments made available through the self-directed brokerage account option being offered under the AEP Retirement Savings 401k Plan shall not be available to Participants in this Plan.

2.13 “Incentive Compensation” means incentive compensation payable pursuant to the terms of annual and long-term incentive compensation plans approved by the Committee for inclusion in the Plan, provided that such incentive compensation shall be determined (a) without regard to (i) any salary or wage reductions made pursuant to sections 125 or 402(e)(3) of the Code or (ii) participant contributions pursuant to a pay reduction agreement under the American Electric Power System Supplemental Retirement Savings Plan, as amended, but (b) after any deferral thereof pursuant to the American Electric Power System Stock Ownership Requirement Plan, as amended. Incentive Compensation will not include Base Compensation, non-annual incentive compensation or bonuses (such as but not limited to project bonuses and sign-on bonuses), severance pay, or relocation payments.

2.14 “Investment Income” means, with respect to Incentive Compensation deferred under this Plan, the earnings, gains and losses that would be attributable to the investment of such deferrals in Stock Units, a Fund or Funds.

2.15 “Key Employee means a Participant who is classified as a “specified employee” at the time of Termination in accordance with the policies adopted by the Human Resources Committee of American Electric Power Company, Inc., (the “HR Committee”) in order to comply with the requirements of Section 409A(a)(2)(B)(i) of the Code and the guidance issued thereunder.

2.16 “Next Date Available” or “NDA” means the June 30 of the calendar year immediately following the calendar year in which falls the Participant’s Termination.

2.17 “Participant” means an Eligible Employee who elects to defer part or all of his or her Incentive Compensation. Except to the extent otherwise specified in this Plan, references to a Participant shall be considered to include a Former Participant.

2.18 “Plan Year” means the twelve-month period commencing each January 1 and ending the following December 31.

2.19 “Retire” means that a Participant terminates employment with AEP and its subsidiaries and affiliates after both attaining age 55 and the completing five years of service with AEP.

2.20 “Stock Unit” means a manner of tracking investment performance, with one Stock Unit having a value equal to one Share (as defined under the American Electric Power System Long-Term Incentive Plan, as amended from time to time).

2.21 “Termination” means termination of employment with the Company and its subsidiaries and affiliates for any reason; provided that effective with respect to Participants whose employment terminates on or after January 1, 2005, determinations as to the circumstances that will be considered a Termination (including a disability and leave of absence) shall be made in a manner consistent with the written policies adopted by the HR Committee from time to time to the extent such policies are consistent with the requirements imposed under Code 409A(a)(2)(A)(i).

2.22 “2005 Distribution Election Period” means the period or periods designated by the Committee during which Participants (or Former Participants) are given the opportunity to select among the distribution options set forth in Article VI, provided that any such period shall end no later than December 31, 2005.

2.23 “2006 Distribution Election Period” means the period or periods designated by the Committee during which Participants (or Former Participants) are given the opportunity to select among the distribution options set forth in Article VI, provided that any such period shall end no later than December 31, 2006.

ARTICLE III

ADMINISTRATION

3.1 The Committee shall have full discretionary power and authority (i) to administer and interpret the terms and conditions of the Plan; (ii) to establish reasonable procedures with which Participants, Former Participant and beneficiaries must comply to exercise any right or privilege established hereunder; and (iii) to delegate its responsibilities or duties hereunder to any person or entity. The rights and duties of the Participants and all other persons and entities claiming an interest under the Plan shall be subject to, and bound by, actions taken by or in connection with the exercise of the powers and authority granted under this Article.

3.2 The Committee may employ agents, attorneys, accountants, or other persons and allocate or delegate to them powers, rights, and duties all as the Committee may consider necessary or advisable to properly carry out the administration of the Plan.

3.3 The Company shall maintain, or cause to be maintained, records showing the individual balances in each Participant’s Account. Statements setting forth the value of the amount credited to the Participant's Account as of a particular date shall be made available to each Participant no less often than quarterly. The maintenance of the Account records and the distribution of statements may be delegated to a record keeper by either the Company or the Committee.

ARTICLE IV

PARTICIPATION

4.1 An Eligible Employee shall become a Participant by making a deferral election during an applicable election period on a form prescribed by the Company to defer part or all of the Eligible Employee’s Incentive Compensation to which such election relates, provided that such election shall not result in the deferral of Incentive Compensation in excess of an amount that allows for the current withholding of Applicable Tax Payments.

4.2 For purposes of Section 4.1, the election period during which Incentive Compensation may be subject to an effective deferral election shall be determined as follows:

(a) To the extent that the Incentive Compensation is “performance-based compensation” (within the meaning of Section 409A(a)(4)(B)(iii) of the Code) that is based on services performed over a period of at least 12 months, the election period shall end no later than six (6) months before the end of the performance period.

(b) To the extent that the Incentive Compensation is not described in Section 4.2(a), the election period shall end on or before December 31 of the calendar year prior to the year in which the services on which the Incentive Compensation is based are to be performed.

(c) Notwithstanding (a) and (b), in the case of the first year in which an Eligible Employee becomes eligible to participate in the Plan, and the Participant has not previously become a Participant in another plan that is required to be aggregated with this Plan under Treasury Regulation Section 1.409A-1(c)(2) or other guidance of the Code, the election period shall end within 30 days after the date such Eligible Employee became eligible to participate and such election shall apply only with respect to compensation paid for services performed subsequent to the election.

4.3 If a deferral election is not made by the end of the election period prescribed by the Company with regard to certain Incentive Compensation that may be earned by an Eligible Employee, no portion of such Incentive Compensation shall be deferred for such Eligible Employee.

4.4 Incentive Compensation that is deferred under this Plan shall be credited to the Participant's Account as follows:

(a) Deferred Incentive Compensation that had been earned and vested prior to January 1, 2005 has been credited to the Participant's Legacy Account Balance. No additional amounts of Incentive Compensation that is deferred under the terms of this Plan shall be credited to a Legacy Account Balance.

(b) Deferred Incentive Compensation that is earned or vested on or after January 1, 2005 shall be credited to the Participant's Active Account Balance. This shall include the deferral under this Plan of Incentive Compensation attributable to 2004 that was subject to discretionary adjustment and first available for payment subsequent to December 31, 2004.

4.5 The Termination (or any subsequent re-employment) of a Participant after such Participant has submitted an election to defer any Incentive Compensation shall not affect the terms of such election with respect to the Incentive Compensation to which such election relates, subject, however, to the provisions for the distribution of any such deferred Incentive Compensation pursuant to the provisions of Article VI.

ARTICLE V

INVESTMENT OF DEFERRED AMOUNTS

5.1 (a) Except to the extent specified otherwise in (b), amounts credited to the Participant's Account (without regard to whether such Account is allocated to such Participant's Legacy Account Balance or Active Account Balance) shall be further credited with earnings as if invested in the Funds selected by the Participant. The Participant may change the selected Funds by providing notification in accordance with the Plan's procedures. Any change in the Funds selected by the Participant shall be implemented in accordance with the Plan's procedures.

(b) For the period from January 1 until June 30 (or such earlier date distributed pursuant to Article 6) immediately following the end of the performance period defined in the Performance Share Award Agreement (the "Holding Period"), amounts attributable to the Participant's voluntary deferral under the terms of this Plan of such performance shares that become earned and vested effective on or after December 31, 2019, shall be tracked as Stock Units initially equal to the number of deferred performance shares (after reduction for applicable withholding pursuant to the Performance Share Award Agreement). During the Holding Period, the amount tracked as Stock Units shall be credited with additional Stock Units determined by reference to dividends paid on Shares, with the number of additional Stock Units due to dividends calculated as the value of the dividend for a number of Stock Units equal to the number of Stock Units credited to the Participant's Account on the dividend record date divided by the closing price of Shares on the dividend payment date. The Participant may not elect to transfer Stock Units to any of the Funds at any time during the Holding Period. As of 11:59 p.m. Eastern Time on June 30 of the Holding Period, all Stock Units then credited to the Participant's Account shall be credited to the AEP Stock Fund under the Plan, using the value of such Stock Units as of the close of the last trading day in the Holding Period.

5.2 Except as otherwise specified in this Plan (for example, per Section 5.1(b), Stock Units may not be transferred), a Participant may elect to transfer all or a portion of the amounts credited to his Account from any Fund or Funds to any other Fund or Funds by providing notification in accordance with the Plan's procedures. Such transfers between Funds may be made in any whole percentage or dollar amounts and shall be implemented in accordance with the Plan's procedures.

5.3 The amount credited to each Participant's Account shall be determined daily based upon the fair market value of the Stock Units, Fund or Funds to which that Account is allocated. The fair market value calculation for a Participant's Account shall be made after all deferrals, distributions, Investment Income and transfers for the day are recorded. A Participant's Account, as adjusted from time to time, shall continue to be credited with Investment Income until the balance of the Account is zero and the Committee anticipates no additional contributions from such Participant.

5.4 The Plan is an unfunded non-qualified deferred compensation plan and therefore the deferrals credited to a Participant's Account and the investment of those deferrals in Stock Units and Fund or Funds are memo accounts that represent general, unsecured liabilities of the Company payable exclusively out of the general assets of the Company. In the event that the Company becomes insolvent, the Participants shall be considered as general unsecured creditors of the Company. A Participant’s rights to benefits under this Plan shall not be subject in any manner to anticipation, alienation, sale, transfer, assignment, pledge encumbrance, attachment or garnishment by creditors of any Participant or any beneficiary.

ARTICLE VI

DISTRIBUTIONS

6.1 Upon a Participant’s Termination for any reason, the Company shall cause the Participant or the Former Participant to be paid the full amount credited to his or her Account in accordance with the following rules:

(a) Legacy Account Balance. With regard to the Participant’s Legacy Account Balance

(1) *Pre-Retirement Cash-Out*. If the Participant has not Retired, the Company shall cause the Participant to be paid the full amount credited to his or her Legacy Account Balance in a single lump sum. The payment shall be made within 60 days after the Participant’s Termination.

(2) *Post-Retirement As Elected*. If the Participant has Retired, amounts that are credited to the Participant's Legacy Account Balance:

(A) Shall be distributed to the Participant in one of the following optional forms as selected by the Participant:

(i) A single lump-sum payment, or

(ii) In annual installment payments over not less than two nor more than ten years.

(B) Shall be paid in the form of distribution selected by the Participant pursuant to paragraph (A) and shall commence within 60 days after the date elected by the Participant on an effective distribution election form. Such date elected by the Participant shall be either (1) the date of the Participant’s Retirement (provided, however, if the Participant was an Executive Officer at the time of his or her Retirement, the earliest commencement date (for account valuation purposes) shall be December 31 of the year of such Executive

Officer's Retirement) or (2) the first, second, third, fourth or fifth anniversary of the Participant's Retirement, as selected by the Participant.

Each Participant shall be provided the opportunity to select the form of distribution [as set forth in paragraph (A)] and benefit commencement date [as set forth in paragraph (B)] with regard to the amounts that are credited to the Participant's Legacy Account Balance when the Participant first elects to participate in the Plan. The Participant may amend his or her distribution election with regard to amounts that are credited to the Participant's Legacy Account Balance at any time prior to the date that is at least twelve (12) months prior to the Participant's Retirement by submitting a distribution election form in accordance with the Plan's procedures; provided that a modification to the Participant's distribution election with regard to amounts that are credited to the Participant's Legacy Account Balance submitted after such 12 month period will be effective if submitted no later than June 30, 2005, but only if the Participant remains employed for at least ninety (90) days following the submission of such distribution election. If the Participant has not submitted an effective distribution election with regard to amounts that are credited to the Participant's Legacy Account Balance at the time of his Retirement, the distribution of the amounts that are credited to the Participant's Legacy Account Balance shall be in the form of a single lump sum payment made within 60 days after the Participant's Retirement. Notwithstanding the preceding sentence, distribution to a Participant who was an Executive Officer at the time of his Retirement, but who has not submitted an effective distribution election with regard to amounts that are credited to the Participant's Legacy Account Balance at the time of his Retirement, shall be in the form of a single lump sum payment within 60 days after December 31 of the calendar year of the Participant's Retirement.

(3) *One-Time Request for In-Service Withdrawal (Penalty Applies)*. A Participant shall be entitled to receive, upon a written request to the Committee that is effective between April 1 and December 31 of any Plan Year, a lump sum distribution from his or her Legacy Account Balance of an amount equal to or greater than 25% of the Participant's Legacy Account Balance as of the date of the request. The date of the request shall be the date the Committee or the Committee's representative receives the request. The lump sum amount to be paid to the Participant shall be subject to a 10% early withdrawal penalty, which penalty shall reduce the amount to be distributed to the Participant or Former Participant. The Participant or Former Participant shall forfeit the amount of the 10% withdrawal penalty. The lump sum amount shall be paid within 60 days after the Committee receives the withdrawal request. Any Participant who elects to receive a benefit under this paragraph shall not be considered an

Eligible Employee with respect to the deferral election periods that apply to such Participant during the three year period that begins as of the date the amount is paid to such Participant under this Section, and such Participant shall not be entitled to request any additional withdrawals under this paragraph prior to the Participant's termination of employment. Any effective deferral elections that have already been submitted by such participant in accordance with Article IV shall be given full force and effect.

(b) Active Account Balance. With regard to the Participant's Active Account Balance the following rules shall apply:

(1) *Form of Distribution*. The Company shall cause the Participant or the Former Participant to be paid the full amount credited to his or her Active Account Balance in accordance with his or her effective election in one of the following forms; provided that options (ii) and (iv) under paragraph (C) of this subsection (b)(1) may be elected on forms submitted on or after such date after November 1, 2019 that such options are first communicated to the Participant and become effective in accordance with the other provisions of this subsection (b).

(A) A single lump sum distribution

(i) as of the First Date Available; or

(ii) as of the Next Date Available; or

(iii) as of the fifth anniversary of the First Date Available; or

(iv) as of the fifth anniversary of the Next Date Available; or

(B) In five (5) annual installments commencing

(i) as of the First Date Available; or

(ii) as of the Next Date Available; or

(iii) as of the fifth anniversary of the First Date Available; or

(iv) as of the fifth anniversary of the Next Date Available; or

(C) In ten (10) annual installments commencing

(i) as of the First Date Available; or

(ii) as of the Next Date Available or

(iii) as of the fifth anniversary of the First Date Available or

(iv) as of the fifth anniversary of the Next Date Available.

(2) *Effective Election*. For this purpose, a Participant's election with respect to the distribution of his or her Active Account Balance shall not be effective unless all of the following requirements are satisfied.

(A) The election is submitted to the Company in writing in a form determined by the Committee to be acceptable;

(B) The election is submitted timely. For purposes of this paragraph, a distribution election will be considered "timely" only if it is submitted prior to the Participant's Termination and it satisfies the requirements of (i), (ii), (iii) or (iv), below, as may be applicable:

(i) Submitted within the applicable election period set forth in Section 4.2, but only if the distribution election is submitted in connection with the Participant's initial deferral election under this Plan; or

(ii) Submitted during the 2005 Distribution Election Period, but only with regard to the first distribution election form submitted by such Participant during that period; or

(iii) Submitted during the 2006 Distribution Election Period by a Participant who then has an Active Account Balance but who was not an Eligible Employee for purposes of a deferral election for 2006 by reason of the change in the definition of Eligible Employee set forth in Section 2.8, but only with regard to the last distribution election form submitted by such Participant during that period; or

(iv) If the Participant is submitting the election to change the timing or form of distribution that is then in effect with respect to the Participant's Active Account Balance other than an effective distribution election submitted as part of the 2005 Distribution Election Period or 2006 Distribution Election Period, such election must be submitted at least one year prior to the date of the Participant's Termination.

(C) If the Participant is submitting the election pursuant to paragraph (b)(2)(B)(iv) to change the timing or form of distribution that is then in effect with respect to the Participant's Active Account Balance (i.e., the Participant is not submitting an election with his initial deferral election [(B)(i)] nor during the 2005 or 2006 Distribution Election Period [(B)(ii) & (B)(iii)], the newly selected option must result in the further deferral of the first scheduled payment from the Participant's Active Account balance by at least 5 years. For purposes of compliance with the rule set forth in Section 409A(a) of the Code (and the regulations issued thereunder), each distribution option described in Section 6.1(b)(1) shall be treated as a single payment as of the first scheduled payment date. The requirement included in the prior plan document that the newly elected option not result in the acceleration of any scheduled payment under the replaced option shall be disregarded.

(D) If the Participant is submitting the election pursuant to paragraph (b)(2)(B)(iii) to change the timing or form of distribution that is then in effect with respect to the Participant's Active Account Balance, the newly selected option may not defer payments that the Participant would have received in 2006 if not for the new distribution election nor cause payments to be made in 2006 if not for the new distribution election.

(3) If a Participant fails to submit an effective distribution election with regard to his Active Account Balance that satisfies the requirements of Section 6.1(b)(2)(B)(i) (with his timely initial deferral election) or Section 6.1(b)(2)(B)(ii) (during the 2005 Distribution Election Period) or Section 6.1(b)(2)(B)(iii) (during the 2006 Distribution Election Period), as applicable, by the date of such initial deferral election or the last day of the 2005 or 2006 Distribution Election Period, respectively, as applicable, such Participant shall be considered to have elected a distribution of his or her Active Account Balance in a single lump sum as of the First Date Available.

(4) *Payout of Stock Units During Holding Period as Shares.* Notwithstanding any other provision of this Section 6.1(b) to the contrary, effective June 1, 2019, to the extent any amount credited in a Participant's Account as Stock Units (including any Stock Units attributable to dividends during the Holding Period) becomes distributable during the Holding Period for those Stock Units, each such distributable Stock Unit shall be converted into a single Share (as defined under the American Electric Power System Long-Term Incentive Plan, as amended from time to time) for delivery in accordance with this section. Fractional Stock Units that constitute less than a single Share may be converted to cash or applied as additional income tax withholding at the Committee's option. The Shares resulting from the conversion of distributable Stock Units shall be delivered to the Participant or to an account set up for the Participant's benefit with a broker/dealer designated by the Company (the "Broker/Dealer Account")

within a reasonable time (generally the next business day) after such Stock Units are converted as described in this section. Participants remain subject to all applicable legal and regulatory restrictions with respect to the resulting shares, such as insider trading restrictions and black-out periods.

Installment distributions that apply to both Stock Units and a Fund or Funds shall be calculated independently so that each component and the total distribution shall reflect the Participant's distribution election. For example, installment payments over 5 years would result in a distribution of one-fifth (20%) of a Participant's Stock Units, one-fifth (20%) of their balance in a Fund or Funds.

6.2 (a) For purposes of this Article, the amount to be distributed to a Participant or Former Participant shall be based upon the value of such individual's Legacy Account Balance or Active Account Balance (as applicable) determined as of the applicable distribution date (or, if that is not a business day, then as of the immediately preceding business day) and shall be paid to such individual as soon as administratively practicable thereafter.

(b) Notwithstanding any other provision of this Article,

(i) if the Participant's Account is $10,000 or less on the Participant's First Date Available (determined without regard to any delay by reason of a Participant's being an Executive Officer), the Committee may require that the full value of the Participant's Account be distributed as of the First Date Available (determined without regard to any delay by reason of a Participant's being an Executive Officer) in a single, lump sum distribution regardless of the form elected by such Participant, provided that such payment is consistent with the limited cash-out right described in Treasury Regulation Section 1.409A-3(j)(4)(v) or other guidance of the Code in that the payment results in the termination and liquidation of the entirety of the Participant's interest under each nonqualified deferred compensation plan (including all agreements, methods, programs, or other arrangements with respect to which deferrals of compensation are treated as having been deferred under a single nonqualified deferred compensation plan under Treasury Regulation 1.409A-1(c)(2) or other guidance of the Code) that is associated with this Plan; and the total payment with respect to any such single nonqualified deferred compensation plan is not greater than the applicable dollar amount under Code Section 402(g)(1)(B). Provided, however,

(ii) Payment to a Participant under any provision of this Plan will be delayed at any time that the Committee reasonably anticipates that the making of such payment will violate Federal securities laws or other applicable law; provided however, that any payments so delayed shall be paid at the earliest date at which the Committee reasonably anticipates that the making of such payment will not cause such violation.

6.3 If an annual distribution is selected, the amount to be distributed in any one-year shall be determined by dividing the Participant’s Legacy Account Balance or Active Account Balance (as appropriate) on the applicable valuation date by the number of years remaining in the elected distribution period. Except to the extent provided otherwise in this Plan, the Participant electing annual distributions shall have the right to direct changes in the investment of the Account in a Fund or Funds in accordance with Article V until the amount credited to the Account is reduced to zero.

ARTICLE VII

BENEFICIARIES

7.1 Each Participant may designate a beneficiary or beneficiaries who shall receive the balance of the Participant's Account if the Participant dies prior to the complete distribution of the Participant's Account. Any designation, or change or rescission of a beneficiary designation shall be made by the Participant’s completion, signature and submission to the Committee of the appropriate beneficiary form prescribed by the Committee. A beneficiary form shall take effect as of the date the form is signed provided that the Committee receives it before taking any action or making any payment to another beneficiary named in accordance with this Plan and any procedures implemented by the Committee. If any payment is made or other action is taken before a beneficiary form is received by the Committee, any changes made on a form received thereafter will not be given any effect. If a Participant fails to designate a beneficiary, or if all beneficiaries named by the Participant do not survive the Participant, the Participant’s Account will be paid to the Participant’s estate. Unless clearly specified otherwise in an applicable court order presented to the Committee prior to the Participant’s death, the designation of a Participant’s spouse as a beneficiary shall be considered automatically revoked as to that spouse upon the legal termination of the Participant’s marriage to that spouse.

7.2 Distribution to a Participant’s beneficiary shall be in the form of a single lump-sum payment within 60 days after the Committee makes a final determination as to the beneficiary or beneficiaries entitled to receive such distribution.

ARTICLE VIII

CLAIMS PROCEDURE

8.1 The following procedures shall apply with respect to claims for benefits under the Plan.

(a) Any Participant or Former Participant or beneficiary who believes he or she is entitled to receive a distribution under the Plan which he or she did not receive or that amounts credited to his or her Account are inaccurate, may file a written claim signed by the Participant, beneficiary or authorized representative with the Claims Reviewer, specifying the basis for the claim. The Claims Reviewer shall provide a claimant with written or electronic notification of its determination on the claim within ninety days after such claim was filed; provided, however, if the Claims Reviewer determines special circumstances require an extension of time for processing the claim, the claimant shall receive within the initial ninety-day period a written notice of the extension for a period of up to ninety days from the end of the initial ninety day period. The extension notice shall indicate the special circumstances requiring the extension and the date by which the Plan expects to render the benefit determination.

(b) If the Claims Reviewer renders an adverse benefit determination under Section 8.1(a), the notification to the claimant shall set forth, in a manner calculated to be understood by the claimant:

(1) The specific reasons for the denial of the claim;

(2) Specific reference to the provisions of the Plan upon which the denial of the claim was based;

(3) A description of any additional material or information necessary for the claimant to perfect the claim and an explanation of why such material or information is necessary, and

(4) An explanation of the review procedure specified in Section 8.2, and the time limits applicable to such procedures, including a statement of the claimant's right to bring a civil action under section 502(a) of the Employee Retirement Income Security Act of 1974, as amended, following an adverse benefit determination on review.

8.2 The following procedures shall apply with respect to the review on appeal of an adverse determination on a claim for benefits under the Plan.

(a) Within sixty days after the receipt by the claimant of an adverse benefit determination, the claimant may appeal such denial by filing with the Committee a written request for a review of the claim. If such an appeal is filed within the sixty day period, the Committee, or a duly appointed representative of the Committee, shall conduct a full and fair review of such claim that takes into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The claimant shall be entitled to submit written comments, documents, records and other information relating to the claim for benefits and shall be provided, upon request and free of charge, reasonable access to, and copies of all documents, records and other information relevant to the claimant's claim for benefits. If the claimant requests a hearing on the claim and the Committee concludes such a hearing is advisable and schedules such a hearing, the claimant shall have the opportunity to present the claimant's case in person or by an authorized representative at such hearing.

(b) The claimant shall be notified of the Committee's benefit determination on review within sixty days after receipt of the claimant's request for review, unless the Committee determines that special circumstances require an extension of time for processing the review. If the Committee determines that such an extension is required, written notice of the extension shall be furnished to the claimant within the initial sixty-day period. Any such extension shall not exceed a period of sixty days from the end of the initial period. The extension notice shall indicate the special circumstances requiring the extension and the date by which the Committee expects to render the benefit determination.

(c) The Committee shall provide a claimant with written or electronic notification of the Plan's benefit determination on review. The determination of the Committee shall be final and binding on all interested parties. Any adverse benefit determination on review shall set forth, in a manner calculated to be understood by the claimant:

(1) The specific reason(s) for the adverse determination;

(2) Reference to the specific provisions of the Plan on which the determination was based;

(3) A statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits; and

(4) A statement of the claimant's right to bring an action under Section 502(a) of ERISA.

ARTICLE IX

MISCELLANEOUS PROVISIONS

9.1 Each Participant agrees that as a condition of participation in the Plan, the Company may withhold applicable federal, state and local taxes; Social Security taxes and Medicare taxes; from any distribution hereunder to the extent that such taxes are then payable.

9.2 In the event the Committee, in its sole discretion, shall find that a Participant, Former Participant or beneficiary is unable to care for his or her affairs because of illness or accident, the Committee may direct that any payment due the Participant or the beneficiary be paid to the duly appointed personal representative of the Participant or beneficiary, and any such payment so made shall be a complete discharge of the liabilities of the Plan and the Company with respect to such Participant or beneficiary.

9.3 The Company intends to continue the Plan indefinitely but reserves the right, in its sole discretion, to modify the Plan from time to time, or to terminate the Plan entirely or to direct the permanent discontinuance or temporary suspension of deferral contributions under the Plan; provided that no such modification, termination, discontinuance or suspension shall reduce the benefits accrued for the benefit of any Participant or beneficiary under the Plan as of the date of such modification, termination, discontinuance or suspension.

9.4 Nothing in the Plan shall interfere with or limit in any way the right of AEP to terminate any Participant’s employment at any time, or confer upon a Participant any right to continue in the employ of AEP.

9.5 The Company intends the following with respect to this Plan: (1) Section 451(a) of the Code would apply to the Participant's recognition of gross income as a result of participation herein; (2) the Participants will not recognize gross income as a result of participation in the Plan unless and until and then only to the extent that distributions are received; (3) the Company will not receive a deduction for amount credited to any Account unless and until and then only to the extent that amounts are actually distributed; (4) the provisions of Parts 2, 3, and 4 of Subtitle B of Title I of ERISA shall not be applicable; and (5) the design and administration of the Plan are intended to comply with the requirements of Section 409A of the Code, to the extent such section is effective and applicable to amounts deferred hereunder. However, no Eligible Employee, Participant, Former Participant, beneficiary or any other person shall have any recourse against the Company, AEP, the Committee, the Claims Reviewer or any of their affiliates, employees, agents, successors, assigns or other representatives if any of those conditions are determined not to be satisfied.

9.6 The Plan shall be construed and administered according to the applicable provisions of ERISA and the laws of the State of Ohio.

9.7 Neither a Participant nor any other person shall have any right to sell, assign, transfer, pledge, mortgage or otherwise encumber, transfer, alienate or convey in advance of actual receipt, the amounts, if any, payable under this Plan. Such amounts payable, or any part thereof, and all rights to such amounts payable are not assignable and are not transferable. No part of the amounts payable shall, prior to actual payment, be subject to seizure, attachment, garnishment or sequestration for the payment of any debts, judgments, alimony or separate maintenance owed by a Participant or any other person. Additionally, no part of any amounts payable shall, prior to actual payment, be transferable by operation of law in the event of a Participant’s or any other person’s bankruptcy or insolvency or be transferable to a spouse as a result of a property settlement or otherwise, except that if necessary to comply with a “qualified domestic relations order,” as defined in ERISA Section 206(d), pursuant to which a court has determined that a spouse or former spouse of a Participant has an interest in the Participant’s benefits under the Plan, the Committee shall distribute the spouse’s or former spouse's interest in the Participant's benefits under the Plan to such spouse or former spouse in accordance with the Participant's election under this Plan as to the time and form of payment.

American Electric Power Service Corporation has caused this amendment and restatement of the American Electric Power System Incentive Compensation Deferral Plan to be signed as of this 25th day of September, 2019.

American Electric Power Service Corporation

By /s/ Tracy Elich
Tracy Elich, Vice President,
Human Resources

AMENDED AND RESTATED AIRCRAFT TIME SHARING AGREEMENT

This Aircraft Time Sharing Agreement (the "**Agreement**") is made and entered into as of the 1st day of October, 2019 by and between American Electric Power Service Corporation, a corporation organized and existing under the laws of the State of New York ("**AEP**"), and Nicholas K. Akins, an individual ("**User**"). This Agreement amends, restates and supersedes in its entirety any previous Aircraft Time Sharing Agreement between AEP and User.

WITNESSETH:

WHEREAS, AEP has rightful possession of the aircraft listed in Appendix A, together with the engines and components installed thereon (the "**Aircraft**"). The parties acknowledge that Appendix A may be modified from time to time as AEP aircraft are replaced and that updates of Appendix A do not require a full amendment to this Agreement; and

WHEREAS, User desires use of the Aircraft on a limited basis; and

WHEREAS, AEP desires to make the Aircraft available to User with flight crew on a non-exclusive time sharing basis in accordance with §91.501 of the Federal Aviation Regulations ("**FARs**"); and

WHEREAS, this Agreement sets forth the understanding of the parties as to the terms under which AEP will provide User with the use, on a non-exclusive time sharing basis, of the Aircraft.

NOW THEREFORE, in consideration of the mutual covenants herein set forth, the parties agree as follows:

1. Provision of Aircraft and Crew. AEP agrees to provide the Aircraft and flight crew to User on a time sharing basis in accordance with the provisions of §§ 91.501(b)(6), 91.501(c)(1) and 91.501(d) of the FARs. AEP shall provide, at its sole expense, qualified flight crew for all flight operations under this Agreement. User shall be entitled to utilize the Aircraft for a total of up to 40 flight hours per year (excluding deadhead flights). Use in excess of such amount shall be permitted only with the approval of the Chairman of the Human Resources Committee ("HRC") of the Board of Directors of American Electric Power Company, Inc. ("AEP Inc.") or AEP Inc.'s Lead Director, provided however, that either may seek the approval of the full HRC at their discretion prior to responding to any such request.

2. Term. The term of this Agreement shall be for a period of one year and shall be automatically extended for additional one-year terms on the same conditions as set forth herein unless earlier terminated as provided for in Section 17.

3. Reimbursement of Expenses. For each flight conducted under this Agreement (including deadhead flights), User shall pay AEP the sum of the expenses of operating each specific flight to the extent permitted by FAR 91.501(d) (or the successor thereto), *i.e.* the sum of the expenses set forth in subsections (a) - (i) below:

(a) Fuel, oil, lubricants, and other additives;

(b) Actual travel expenses of the crew, including food, lodging, and ground transportation;
(c) Hangar and tie-down costs away from the Aircraft's base of operation;
(d) Insurance obtained for the specific flight;
(e) Landing fees, airport taxes, and similar assessments;
(f) Customs, foreign permit, and similar fees directly related to the flight;
(g) Incremental catering and other food and beverages;
(h) Passenger ground transportation; and
(i) Incremental flight planning and weather contract services required for a specific flight under this Agreement.

4. Invoicing and Payment. All payments to be made to AEP by User hereunder shall be paid in the manner set forth in this Section 4. AEP will pay to suppliers, employees, contractors and governmental entities all expenses related to the operation of the Aircraft hereunder in the ordinary course. As to each flight operated hereunder, AEP shall provide or cause to be provided to User an invoice for the charges specified in Section 3 of this Agreement (plus domestic or international air transportation excise taxes, as applicable, imposed by the Internal Revenue Code), such invoice to be issued within forty-five (45) days after the end of each quarter of a calendar year for flights performed within such quarter. User shall pay AEP the full amount of such invoice within thirty (30) days of the date of the invoice. AEP may net the amount of such invoices from amounts payable from AEP to User including payroll or similar payments. In the event AEP has not received supplier invoices for reimbursable charges relating to such flight prior to such invoicing, AEP may issue supplemental invoice(s) for such charge(s) to User, and User shall pay such charge(s) within thirty (30) days of the date of each supplemental invoice.

5. Flight Requests. User will provide AEP with flight requests and proposed flight schedules as far in advance as possible, and in any case at least twenty-four (24) hours in advance of User's desired departure, except in urgent or emergency situations. Flight requests shall be in a form, whether oral or written, mutually convenient to and agreed upon by the parties. AEP shall notify User as to whether or not the requested use of the Aircraft can be accommodated. AEP's prior planned utilization of the Aircraft will take precedence over User's use and an Aircraft may not be available due to maintenance, operational, crew scheduling or other considerations. AEP shall have sole and exclusive authority over the scheduling of the Aircraft. AEP shall not be liable to User or any other person for loss, injury, or damage occasioned by the delay or failure to furnish the Aircraft and crew pursuant to this Agreement for any reason. In addition to requested schedules and departure times, User shall provide at least the following information for each proposed flight reasonably in advance of the desired departure time as required by AEP or its flight crew:

(a) departure point;
(b) destination;
(c) date and time of flight;
(d) number and identity of anticipated passengers (which shall always include User, whether or not there will be additional guests);
(e) nature of any unusual luggage and/or cargo expected to be carried;
(f) date and time of return flight, if any;

(g) the purpose of the trip, which shall exclude all travel primarily for commuting, but which may include, for example, entertainment, visiting family, travel for business other than that of the employer providing the flight, attending a funeral or seeking medical care; and

(h) any other information concerning the proposed flight that may be pertinent to or required by AEP or its flight crew.

6. Operational Authority and Control. AEP shall be responsible for the physical and technical operation of the Aircraft used under this Agreement, and shall retain full authority and control including exclusive operational control and possession of such Aircraft at all times during the use of Aircraft under this Agreement. In accordance with applicable FARs, the qualified flight crew provided by AEP will exercise all required duties and responsibilities in regard to the safety of each flight conducted hereunder. The pilot-in-command shall have absolute discretion in all matters concerning the preparation of an Aircraft used under this Agreement for flight and the flight itself, the load carried and its distribution, the decision whether or not a flight shall be undertaken, the route to be flown, the place where landings shall be made, and all other matters relating to operation of an Aircraft under this Agreement. User specifically agrees that the flight crew shall have final and complete authority to delay, divert or cancel any flight for any reason or condition which in the sole judgment of the pilot-in-command could compromise the safety of the flight, and to take any other action which in the sole judgment of the pilot-in-command is necessitated by considerations of safety. No such action of the pilot-in-command shall create or support any liability to User or any other person for loss, injury, damage or delay. The parties further agree that AEP shall not be liable for delay or failure to furnish the Aircraft and crew pursuant to this Agreement, including, for example when such failure is caused by government regulation or authority, mechanical difficulty or breakdown, war, terrorism, civil commotion, strikes or labor disputes, weather conditions, acts of God, or other circumstances beyond AEP’s reasonable control. User agrees that AEP's operation of aircraft under this Agreement shall be strictly within the guidelines of the AEP's Flight Operations Department manual and FAR Part 91.

7. Aircraft Maintenance. AEP shall, at its own expense, cause the Aircraft to be inspected, maintained, serviced, repaired, overhauled, and tested in accordance with FAR Part 91 so that the Aircraft will remain in good operating condition and in a condition consistent with its airworthiness certification. Performance of maintenance, preventive maintenance or inspection shall not be delayed or postponed for the purpose of scheduling the Aircraft unless such maintenance or inspection can safely be conducted at a later time in compliance with applicable laws, regulations and requirements, and such delay or postponement is consistent with the sound discretion of the pilot-in-command. In the event that any maintenance is required that will interfere with User's requested or scheduled flights, AEP or AEP's pilot-in-command, shall notify User of the maintenance required, the effect on the ability to comply with User's requested or scheduled flights and the manner and time and date in which the parties may later conduct such flight(s), if at all.

8. Insurance.

AEP will maintain or cause to be maintained in full force and effect throughout the term of this Agreement Aviation Liability insurance in respect of the Aircraft in an amount at least equal to $200 million combined single limit for bodily injury to or death of persons (including passengers) and property damage liability (limits may be met with combination of Excess Liability limits that attach to Aviation Liability policy). AEP shall (i) make reasonable efforts to provide for thirty (30) days prior written notice to User before any lapse, alteration, termination or cancellation of insurance shall be effective as to User, (ii) request provisions whereby the insurer(s) irrevocably and unconditionally waive all rights of subrogation they may have or acquire against User, (iii) include User as an additional insured, and (iv) have insurer include a cross-liability clause to the effect that such insurance, except for the limits of liability, shall operate to give User the same protection as if there were a separate policy issued to the User.

9. Use of Aircraft.

(a) User warrants that:

(i) He will use the Aircraft under this Agreement for and only for his own account, including the carriage of his guests, and will not use, or hold out the use of, the Aircraft for the purpose of providing transportation of passengers or cargo for compensation or hire;

(ii) He will not permit any lien, security interest or other charge or encumbrance to attach against the Aircraft as a result of his actions or inactions, and shall not convey, mortgage, assign, lease or in any way alienate the Aircraft or AEP's rights hereunder;

(iii) During the term of this Agreement, he will abide by and conform to, and will cause all passengers to abide by and conform to, all such laws, governmental and airport orders, rules, and regulations as shall from time to time be in effect relating in any way to the operation or use of the Aircraft; and

(iv) He will not use Aircraft under this Agreement for any trip for which the primary purpose is commuting travel.

(b) User's use shall include the use of the Aircraft by his family, friends and guests (including spouses, children, parents, employees, etc.) provided they accompany User on the flight and the terms of the use by such other individuals is consistent with the FARs.

10. Limitation of Liability. NEITHER AEP (NOR ITS AFFILIATES, EMPLOYEES, OFFICERS, DIRECTORS, AGENTS OR REPRESENTATIVES) MAKES, HAS MADE OR SHALL BE DEEMED TO MAKE OR HAVE MADE ANY WARRANTY OR REPRESENTATION, EITHER EXPRESS OR IMPLIED, WRITTEN OR ORAL, WITH RESPECT TO ANY AIRCRAFT TO BE USED HEREUNDER OR ANY ENGINE OR COMPONENT THEREOF INCLUDING, WITHOUT LIMITATION, ANY WARRANTY AS TO DESIGN, COMPLIANCE WITH SPECIFICATIONS, QUALITY OF MATERIALS OR WORKMANSHIP, MERCHANTABILITY, FITNESS FOR ANY PURPOSE, USE OR OPERATION, AIRWORTHINESS, SAFETY, PATENT, TRADEMARK OR COPYRIGHT INFRINGEMENT OR TITLE. USER AGREES THAT ITS SOLE RECOURSE AND EXCLUSIVE REMEDY FOR ANY DAMAGE, LOSS, OR EXPENSE ARISING OUT OF THIS AGREEMENT OR THE SERVICES PROVIDED HEREUNDER OR CONTEMPLATED SHALL BE SUCH PROCEEDS TO WHICH HE IS ENTITLED FROM THE INSURANCE

PROVIDED BY AEP UNDER THIS AGREEMENT. USER HEREBY WAIVES ON BEHALF OF HIMSELF AND HIS HEIRS, EXECUTORS, SUCCESSORS, AND ASSIGNS OF ANY KIND WHATSOEVER ANY RIGHT TO RECOVER ANY DAMAGE, LOSS, OR EXPENSE ARISING OUT OF THIS AGREEMENT OR THE SERVICES PROVIDED HEREUNDER OR CONTEMPLATED HEREBY EXCEPT AS SPECIFICALLY PROVIDED IN THE PRECEDING SENTENCE. IN NO EVENT SHALL AEP BE LIABLE FOR OR HAVE ANY DUTY FOR INDEMNIFICATION OR CONTRIBUTION TO THE OTHER PARTY FOR ANY CLAIMED INDIRECT, SPECIAL, CONSEQUENTIAL, OR PUNITIVE DAMAGES, OR FOR ANY DAMAGES REGARDLESS OF WHETHER IT KNEW OR SHOULD HAVE KNOWN OF THE POSSIBILITY OF SUCH DAMAGE, LOSS OR EXPENSE. The provisions of this Section 10 shall survive the termination or expiration of this Agreement.

11. Base of Operations. For purposes of this Agreement, the base of operation of the Aircraft is John Glenn International Airport, Columbus, Ohio; provided, that such base may be changed upon notice from AEP to User.

12. Subordination. The parties acknowledge that the AEP's possession of Aircraft used under this Agreement is pursuant to a lease agreement between AEP and the Party(ies) listed in Appendix A ("**Lessor**") and that (A) any rights of User contained herein are and remain, subject and subordinate to the Lessor's interest in and with respect to the Aircraft under the lease documents, (B) this Agreement shall not convey any lien on, or other property interest in or against the Aircraft used under this Agreement, and (C) User is not permitted any disposition of or to create any lien against the Aircraft.

13. Notices and Communications. All notices and other communications under this Agreement shall be in writing (except as permitted in Section 5) and shall be given (and shall be deemed to have been duly given upon receipt or refusal to accept receipt) by personal delivery, by facsimile, or by a reputable overnight courier service, addressed as follows:

If to AEP: American Electric Power Service Corporation
1 Riverside Plaza, 01
Columbus, Ohio 43215
Attn: Stanley E. Partlow, Jr., VP & Chief Security Officer
Telephone: 614-716-3020

If to User: Nicholas K. Akins
1 Riverside Plaza, 30
Columbus, Ohio 43215
Telephone: 614-716-3800

or to such other person or address as either party may from time to time designate in writing to the other party. Neither party shall object to the manner or timing of notice for any notice which was actually received by such party.

14. Entire Agreement. This Agreement constitutes the entire understanding between the parties with respect to its subject matter, and there are no representations, warranties, rights,

obligations, liabilities, conditions, covenants, or agreements other than as expressly set forth herein.

15. Further Acts. AEP and User shall from time to time perform such other and further acts and execute such other and further instruments as may be required by law or may be reasonably necessary (i) to carry out the intent and purpose of this Agreement, and (ii) to establish, maintain and protect the respective rights and remedies of the other party.

16. Successors and Assigns. Neither this Agreement nor any party's interest herein shall be assignable to any other party. This Agreement shall inure to the benefit of and be binding upon the parties hereto, their heirs, representatives and successors.

17. Termination. Either party may terminate this Agreement for any reason upon prior written notice to the other, such termination to become effective thirty (30) days from the date of the notice; provided, that this Agreement may be terminated as a result of a breach by either party of its obligations under this Agreement on thirty (30) days' written notice by the non-breaching party to the breaching party; and provided further, that this Agreement may be terminated on such shorter notice as may be required to comply with applicable laws, regulations, the requirements of any financial institution with an interest in the Aircraft, or insurance requirements or in the event the insurance to be provided hereunder is not in full force and effect or such breaching party's acts or omissions violate the terms of such insurance. Notwithstanding any termination of this Agreement, User shall remain responsible for the costs and expenses incurred during the term.

18. Governing Law and Consent to Jurisdiction. This Agreement shall be construed under and the legal relations between the parties shall be governed by the laws of the State of Ohio. The parties hereby consent and agree to submit to the exclusive jurisdiction and venue of any state or federal court in the State of Ohio in any proceedings hereunder, and each hereby waives any objection to any such proceedings based on improper venue or forum non-conveniens or similar principles. The parties hereto hereby further consent and agree to the exercise of such personal jurisdiction over them by such courts with respect to any such proceedings, waive any objection to the assertion or exercise of such jurisdiction and consent to process being served in any such proceedings in the manner provided for the giving of notices hereunder.

19. Severability. If any provision of this Agreement is held to be illegal, invalid or unenforceable, the legality, validity and enforceability of the remaining provisions shall not be affected or impaired.

20. Amendment or Modification. This Agreement constitutes the entire agreement between the parties with respect to the subject matter hereof and is not intended to confer upon any person or entity any rights or remedies hereunder which are not expressly granted herein. This Agreement may be amended or modified only in writing duly executed by the parties hereto.

21. Counterparts.

This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, and all of which shall constitute one and the same Agreement, binding on all the parties notwithstanding that all the parties are not signatories to the same counterpart.

22. TRUTH IN LEASING STATEMENT PURSUANT TO SECTION 91.23 OF THE FEDERAL AVIATION REGULATIONS:

(a) AEP CERTIFIES THAT THE AIRCRAFT HAS BEEN INSPECTED AND MAINTAINED WITHIN THE TWELVE (12) MONTH PERIOD PRECEDING THE DATE OF THIS AGREEMENT (OR SUCH SHORTER PERIOD AS AEP SHALL HAVE POSSESSED THE AIRCRAFT) IN ACCORDANCE WITH THE PROVISIONS OF PART 91 OF THE FEDERAL AVIATION REGULATIONS, AND THAT ALL APPLICABLE REQUIREMENTS FOR THE AIRCRAFT'S MAINTENANCE AND INSPECTION THEREUNDER HAVE BEEN MET.

(B) AEP AGREES, CERTIFIES AND ACKNOWLEDGES, AS EVIDENCED BY ITS SIGNATURE HEREIN, THAT WHENEVER THE AIRCRAFT IS OPERATED UNDER THIS AGREEMENT, AEP SHALL BE KNOWN AS, CONSIDERED, AND SHALL IN FACT BE THE OPERATOR OF THE AIRCRAFT, AND THAT AEP UNDERSTANDS ITS RESPONSIBILITIES FOR COMPLIANCE WITH APPLICABLE FEDERAL AVIATION REGULATIONS.

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215
By: /s/ Stanley E. Partlow, Jr.
Name: Stanley E. Partlow, Jr.
Title: VP & Chief Security Officer

(C) THE PARTIES UNDERSTAND THAT AN EXPLANATION OF FACTORS AND PERTINENT FEDERAL AVIATION REGULATIONS BEARING ON OPERATIONAL CONTROL CAN BE OBTAINED FROM THE NEAREST FAA FLIGHT STANDARDS DISTRICT OFFICE. USER UNDERSTANDS THAT A TRUE COPY OF THIS AGREEMENT WILL BE SENT BY AEP TO: FEDERAL AVIATION ADMINISTRATION, AIRCRAFT REGISTRATION BRANCH, ATTN. TECHNICAL SECTION (AVN-450), P.O. BOX 25724, OKLAHOMA CITY, OKLAHOMA 73125, WITHIN 24 HOURS AFTER ITS EXECUTION, AS REQUIRED BY FAR SECTION 91.23(c)(1). FURTHER, THE PARTIES ACKNOWLEDGE THAT NO OPERATIONS UNDER THIS TIME SHARING AGREEMENT SHALL BE PERMITTED UNTIL TIMELY NOTICE HAS BEEN DELIVERED OF THE FIRST FLIGHT HEREUNDER TO THE FLIGHT STANDARDS DISTRICT OFFICE TO THE POINT OF DEPARTURE AS REQUIRED BY FAR SECTION 91.23(c)(3).

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the parties hereto have caused this Aircraft Time Sharing Agreement to be duly executed on the day and year first above written.

American Electric Power Service Corporation	USER: Nicholas K. Akins
By: /s/ Stanley E. Partlow, Jr.	By: /s/ Nicholas K. Akins
Name: Stanley E. Partlow, Jr. Title: VP & Chief Security Officer	

A legible copy of this Agreement shall be kept in the Aircraft for all operations conducted hereunder as required by FAR Section 91.23(c)(2).

Appendix A

Listing of Aircraft

Note: The following list of Aircraft is effective as of the date below and may be modified from time to time as AEP aircraft are replaced. This list may be amended without formal amendment to the Agreement by the initial of a replacement Appendix A below.

Make	**Model**	**Serial Number**	**Registration Number**	**Lessor**
Embraer	EMB-550	55000075	N891AE	PNC Equipment Finance LLC
Hawker Beechcraft Corp.	Hawker 900XP	HA-0168	N50AE	The Huntington National Bank
Hawker Beechcraft Corp.	Hawker 900XP	HA-0171	N754AE	The Huntington National Bank

Date: September 24, 2019

American Electric Power
Service Corporation

Initialed: /s/ SEP

Name: Stanley E. Partlow, Jr.
Title: VP & Chief Security Officer

USER:
Nicholas K. Akins

Initialed: /s/ NKA

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-Q of American Electric Power Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: <u>/s/ Nicholas K. Akins</u>
Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-Q of AEP Transmission Company, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: /s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-Q of AEP Texas Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: October 24, 2019	By:	/s/ Nicholas K. Akins
		Nicholas K. Akins
		Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-Q of Appalachian Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: /s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-Q of Indiana Michigan Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: October 24, 2019

By: /s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-Q of Ohio Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019 By: /s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-Q of Public Service Company of Oklahoma;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: /s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-Q of Southwestern Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: /s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-Q of American Electric Power Company, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-Q of AEP Transmission Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-Q of AEP Texas Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-Q of Appalachian Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: October 24, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-Q of Indiana Michigan Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: October 24, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-Q of Ohio Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-Q of Public Service Company of Oklahoma;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-Q of Southwestern Electric Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 24, 2019	By:	/s/ Brian X. Tierney
		Brian X. Tierney
		Chief Financial Officer

Exhibit 32(a)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of American Electric Power Company, Inc. (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of AEP Transmission Company, LLC (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to AEP Transmission Company, LLC and will be retained by AEP Transmission Company, LLC and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of AEP Texas Inc. (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to AEP Texas Inc. and will be retained by AEP Texas Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Appalachian Power Company (the "Company") on Form 10-Q (the "Report") for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Appalachian Power Company and will be retained by Appalachian Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Indiana Michigan Power Company (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Indiana Michigan Power Company and will be retained by Indiana Michigan Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Ohio Power Company (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Ohio Power Company and will be retained by Ohio Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Public Service Company of Oklahoma (the "Company") on Form 10-Q (the "Report") for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Public Service Company of Oklahoma and will be retained by Public Service Company of Oklahoma and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Southwestern Electric Power Company (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Southwestern Electric Power Company and will be retained by Southwestern Electric Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of American Electric Power Company, Inc. (the "Company") on Form 10-Q (the "Report") for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of AEP Transmission Company, LLC (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to AEP Transmission Company, LLC and will be retained by AEP Transmission Company, LLC and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of AEP Texas Inc. (the "Company") on Form 10-Q (the "Report") for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to AEP Texas Inc. and will be retained by AEP Texas Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Appalachian Power Company (the "Company") on Form 10-Q (the "Report") for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Appalachian Power Company and will be retained by Appalachian Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Indiana Michigan Power Company (the "Company") on Form 10-Q (the "Report") for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Indiana Michigan Power Company and will be retained by Indiana Michigan Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Ohio Power Company (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Ohio Power Company and will be retained by Ohio Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Public Service Company of Oklahoma (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Public Service Company of Oklahoma and will be retained by Public Service Company of Oklahoma and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Quarterly Report of Southwestern Electric Power Company (the “Company”) on Form 10-Q (the “Report”) for the quarter ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

October 24, 2019

A signed original of this written statement required by Section 906 has been provided to Southwestern Electric Power Company and will be retained by Southwestern Electric Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

MINE SAFETY INFORMATION

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of Dolet Hills Lignite Company (DHLC), a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. DHLC received the following notices of violation and proposed assessments under the Mine Act for the quarter ended September 30, 2019:

Number of Citations for S&S Violations of Mandatory Health or Safety Standards under 104 *		0
Number of Orders Issued under 104(b) *		0
Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards under 104(d) *		0
Number of Flagrant Violations under 110(b)(2) *		0
Number of Imminent Danger Orders Issued under 107(a) *		0
Total Dollar Value of Proposed Assessments **	$	121
Number of Mining-related Fatalities		0

* References to sections under the Mine Act.
** Includes assessments paid in the third quarter of 2019 for citations issued in the second quarter of 2019.

There are currently no legal actions pending before the Federal Mine Safety and Health Review Commission.