UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended **December 31, 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

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant American Electric Power Company, Inc., AEP Transmission Company, LLC, Indiana Michigan Power Company and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.	Yes	☒	No	☐
Indicate by check mark if the registrants AEP Texas Inc., Appalachian Power Company, Ohio Power Company, Public Service Company of Oklahoma, are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.	Yes	☐	No	☒
Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.	Yes	☐	No	☒
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 registrant was 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 I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

	Aggregate Market Value of Voting and Non-Voting Common Equity Held by Nonaffiliates of the Registrants as of June 30, 2019 the Last Trading Date of the Registrants' Most Recently Completed Second Fiscal Quarter	Number of Shares of Common Stock Outstanding of the Registrants as of December 31, 2019
American Electric Power Company, Inc.	$43,491,855,142	494,169,471
		($6.50 par value)
AEP Texas Inc.	None	100
		($0.01 par value)
AEP Transmission Company, LLC (a)	None	NA
Appalachian Power Company	None	13,499,500
		(no par value)
Indiana Michigan Power Company	None	1,400,000
		(no par value)
Ohio Power Company	None	27,952,473
		(no par value)
Public Service Company of Oklahoma	None	9,013,000
		($15 par value)
Southwestern Electric Power Company	None	7,536,640
		($18 par value)

(a) 100% interest is held by AEP Transmission Holdco.
NA Not applicable.

Note on Market Value of Common Equity Held by Nonaffiliates

American Electric Power Company, Inc. owns all of the common stock of AEP Texas Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company and all of the LLC membership interest in AEP Transmission Company, LLC (see Item 12 herein).

Documents Incorporated By Reference

Description	Part of Form 10-K into which Document is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2019:	Part II
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	
Southwestern Electric Power Company	
Portions of Proxy Statement of American Electric Power Company, Inc. for 2020 Annual Meeting of Shareholders.	Part III

This combined Form 10-K 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. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

You can access financial and other information at AEP's website, including AEP's Principles of Business Conduct, certain committee charters and Principles of Corporate Governance. The address is www.AEP.com. Investors can obtain copies of our SEC filings from this site free of charge, as well as from the SEC website at www.sec.gov.

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority-owned consolidated subsidiaries and consolidated affiliates.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP Energy Supply, LLC	A nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
AEP OnSite Partners	A division of AEP Energy Supply, LLC that builds, owns, operates and maintains customer solutions utilizing existing and emerging distributed technologies.
AEP Renewables	A division of AEP Energy Supply, LLC that develops and/or acquires large scale renewable projects that are backed with long-term contracts with creditworthy counter parties.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in deregulated markets.
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.
AEPTHCo	AEP Transmission Holding Company, LLC, a subsidiary of AEP, an intermediate holding company that owns transmission operations joint ventures and AEPTCo.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APTCo	AEP Appalachian Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
Conesville Plant	A single unit coal-fired generation plant totaling 651 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, 2,288 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
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.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIP	Federal Implementation Plan.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.

Term	Meaning
IMTCo	AEP Indiana Michigan Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MW	Megawatt.
MWh	Megawatt-hour.
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_x	Nitrogen oxide.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OHTCo	AEP Ohio Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
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.
OKTCo	AEP Oklahoma Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
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.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Racine	A generation plant consisting of two hydroelectric generating units totaling 48 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.
REP	Texas Retail Electric Provider.
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.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SEC	U.S. Securities and Exchange Commission.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.

SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.

Term	Meaning
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, each of which is geographically aligned with AEP existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
SWTCo	AEP Southwestern Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
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.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.
WVTCo	AEP West Virginia Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- 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 particulate matter and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including 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, other postretirement benefits, 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, except as required by law. For a more detailed discussion of these factors, see “Risk Factors” in Part I of this report.

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

PART I

ITEM 1. BUSINESS

GENERAL

Overview and Description of Major Subsidiaries

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries.

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring laws in Michigan, Ohio and the ERCOT area of Texas have caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

The member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity and transportation and handling of fuel. The companies of the AEP System also obtain certain accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, AEPSC.

As of December 31, 2019, the subsidiaries of AEP had a total of 17,408 employees. Because it is a holding company rather than an operating company, AEP has no employees. The material subsidiaries of AEP are as follows:

AEP Texas

Organized in Delaware in 1925, AEP Texas is engaged in the transmission and distribution of electric power to approximately 1,049,000 retail customers through REPs in west, central and southern Texas. As of December 31, 2019, AEP Texas had 1,585 employees. Among the principal industries served by AEP Texas are petroleum and coal products manufacturing, chemical manufacturing, oil and gas extraction, pipeline transportation and primary metal manufacturing. The territory served by AEP Texas also includes several military installations and correctional facilities. AEP Texas is a member of ERCOT. AEP Texas is part of AEP's Transmission and Distribution Utilities segment.

AEPTCo

Organized in Delaware in 2006, AEPTCo is a holding company for the State Transcos. The State Transcos develop and own new transmission assets that are physically connected to the AEP System. Individual State Transcos (a) have obtained the approvals necessary to operate in Indiana, Kentucky, Michigan, Ohio, Oklahoma and West Virginia, subject to any applicable siting requirements, (b) are authorized to submit projects for commission approval in Virginia and (c) have been granted consent to enter into a joint license agreement that will support investment in Tennessee. Neither AEPTCo nor its subsidiaries have any employees. Instead, AEPSC and certain AEP utility subsidiaries provide services to these entities. AEPTCo is part of the AEP Transmission Holdco segment.

APCo

Organized in Virginia in 1926, APCo is engaged in the generation, transmission and distribution of electric power to approximately 956,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo owns 6,629 MWs of generating capacity. APCo uses its generation to serve its retail and other customers. As of December 31, 2019, APCo had 1,699 employees. Among the principal industries served by APCo are coal mining, primary metals, pipeline transportation, chemical manufacturing and paper manufacturing. APCo is a member of PJM. APCo is part of AEP's Vertically Integrated Utilities segment.

I&M

Organized in Indiana in 1907, I&M is engaged in the generation, transmission and distribution of electric power to approximately 599,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M owns or leases 3,634 MWs of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2019, I&M had 2,336 employees. Among the principal industries served are primary metals, transportation equipment, chemical manufacturing, plastics and rubber products and fabricated metal product manufacturing. I&M is a member of PJM. I&M is part of AEP's Vertically Integrated Utilities segment.

KPCo

Organized in Kentucky in 1919, KPCo is engaged in the generation, transmission and distribution of electric power to approximately 165,000 retail customers in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo owns 1,060 MWs of generating capacity. KPCo uses its generation to serve its retail and other customers. As of December 31, 2019, KPCo had 500 employees. Among the principal industries served are petroleum and coal products manufacturing, chemical manufacturing, coal mining, oil and gas extraction and primary metals. KPCo is a member of PJM. KPCo is part of AEP's Vertically Integrated Utilities segment.

KGPCo

Organized in Virginia in 1917, KGPCo provides electric service to approximately 48,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. KGPCo does not own any generating facilities and is a member of PJM. It purchases electric power from APCo for distribution to its customers. As of December 31, 2019, KGPCo had 54 employees. KGPCo is part of AEP's Vertically Integrated Utilities segment.

OPCo

Organized in Ohio in 1907 and reincorporated in 1924, OPCo is engaged in the transmission and distribution of electric power to approximately 1,494,000 retail customers in Ohio. OPCo purchases energy and capacity at auction to serve generation service customers who have not switched to a competitive generation supplier. As of December 31, 2019, OPCo had 1,681 employees. Among the principal industries served by OPCo are primary metals, petroleum and coal products manufacturing, plastics and rubber products, chemical manufacturing, fabricated metal product manufacturing and data centers. OPCo is a member of PJM. OPCo is part of AEP's Transmission and Distribution Utilities segment.

PSO

Organized in Oklahoma in 1913, PSO is engaged in the generation, transmission and distribution of electric power to approximately 559,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO owns 3,833 MWs of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2019, PSO had 1,097 employees. Among the principal industries served by PSO are paper manufacturing, oil and gas extraction, petroleum and coal products manufacturing, transportation equipment and pipeline transportation. PSO is a member of SPP. PSO is part of AEP's Vertically Integrated Utilities segment.

SWEPCo

Organized in Delaware in 1912, SWEPCo is engaged in the generation, transmission and distribution of electric power to approximately 540,000 retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo owns 5,169 MWs of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2019, SWEPCo had 1,469 employees. Among the principal industries served by SWEPCo are petroleum and coal products manufacturing, food manufacturing, paper manufacturing, oil and gas extraction and chemical manufacturing. The territory served by SWEPCo includes several military installations, colleges and universities. SWEPCo also owns and operates a lignite coal mining operation. SWEPCo is a member of SPP. SWEPCo is part of AEP's Vertically Integrated Utilities segment.

WPCo

Organized in West Virginia in 1883 and reincorporated in 1911, WPCo provides electric service to approximately 42,000 retail customers in northern West Virginia and in supplying and marketing electric power at wholesale to other market participants. WPCo owns 780 MWs of generating capacity which it uses to serve its retail and other customers. Among the principal industries served by WPCo are coal mining, primary metals, pipeline transportation, chemical manufacturing and paper manufacturing. WPCo is a member of PJM. As of December 31, 2019, WPCo had 50 employees. WPCo is part of AEP's Vertically Integrated Utilities segment.

Service Company Subsidiary

AEPSC is a service company subsidiary that provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to AEP subsidiaries. The executive officers of AEP and certain of the executive officers of its public utility subsidiaries are employees of AEPSC. As of December 31, 2019, AEPSC had 6,439 employees.

Company Website and Availability of SEC Filings

Our principal corporate website address is www.aep.com. Information on our website is not incorporated by reference herein and is not part of this Form 10-K. We make available free of charge through our website our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements and other information regarding AEP.

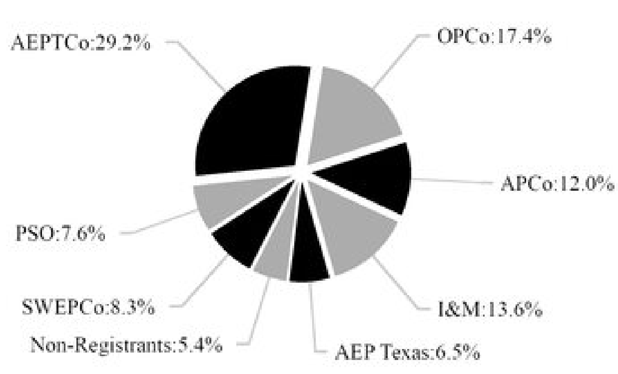
Public Utility Subsidiaries by Jurisdiction

The following table illustrates certain regulatory information with respect to the jurisdictions in which the public utility subsidiaries of AEP operate:

Principal Jurisdiction	AEP Utility Subsidiaries Operating in that Jurisdiction	Authorized Return on Equity (a)	
FERC	AEPTCo - PJM	10.35%	
	AEPTCo - SPP	10.50%	
Ohio	OPCo	10.20%	(b)
West Virginia	APCo	9.75%	
	WPCo	9.75%	
Virginia	APCo	9.42%	
Indiana	I&M	9.95%	
Michigan	I&M	9.86%	
Texas	AEP Texas	9.96%	
	SWEPCo	9.60%	
Tennessee	KGPCo	9.85%	
Kentucky	KPCo	9.70%	
Louisiana	SWEPCo	9.80%	
Arkansas	SWEPCo	9.45%	
Oklahoma	PSO	9.40%	

(a) Identifies the predominant authorized ROE and may not include other, less significant, permitted recovery. Actual ROE varies from authorized ROE.
(b) Authorized ROE was approved in OPCo's last distribution base case. The authorized ROE for riders with an approved equity return (e.g. Distribution Investment Rider) is 10.00%. See "Ohio Electric Security Plan Filings" section of Note 4 included in the 2019 Annual Report.

Percentage of AEP Consolidated Pretax Income by Registrant Subsidiary (a)
for the year ended December 31, 2019



(a) Pretax income does not include intercompany eliminations.

CLASSES OF SERVICE

The principal classes of service from which AEP's subsidiaries derive revenues and the amount of such revenues during the years ended December 31, 2019, 2018 and 2017 are as follows:

Description	Years Ended December 31, 2019	2018	2017
	(in millions)		
Vertically Integrated Utilities Segment			
Retail Revenues			
Residential Sales	$ 3,641.2	$ 3,818.6	$ 3,399.8
Commercial Sales	2,151.1	2,223.7	2,124.4
Industrial Sales	2,178.3	2,261.3	2,180.8
PJM Net Charges	(0.2)	0.4	(1.1)
Other Retail Sales	179.4	186.8	181.7
Total Retail Revenues (a)	8,149.8	8,490.8	7,885.6
Wholesale Revenues			
Off-system Sales	814.5	888.0	907.4
Transmission	200.7	263.7	202.2
Total Wholesale Revenues	1,015.2	1,151.7	1,109.6
Other Electric Revenues	93.8	93.7	106.1
Provision for Rate Refund	(44.7)	(210.1)	(46.4)
Other Operating Revenues	31.6	30.6	40.2
Sales to Affiliates	121.4	88.8	96.9
Total Revenues Vertically Integrated Utilities Segment	$ 9,367.1	$ 9,645.5	$ 9,192.0
Transmission and Distribution Utilities Segment			
Retail Revenues			
Residential Sales	$ 2,084.5	$ 2,213.6	$ 2,085.3
Commercial Sales	1,148.8	1,266.7	1,205.8
Industrial Sales	426.5	517.2	489.2
Other Retail Sales	43.7	43.1	43.1
Total Retail Revenues (a)	3,703.5	4,040.6	3,823.4
Wholesale Revenues			
Off-system Sales	93.0	119.3	100.5
Transmission	437.7	394.7	359.6
Total Wholesale Revenues	530.7	514.0	460.1
Other Electric Revenues	58.6	54.5	48.4
Provision for Rate Refund	12.5	(69.2)	(11.4)
Other Operating Revenues	13.7	12.4	8.4
Sales to Affiliates	163.5	100.8	90.4
Total Revenues Transmission and Distribution Utilities Segment	$ 4,482.5	$ 4,653.1	$ 4,419.3
AEP Transmission Holdco Segment			
Transmission Revenues	$ 265.1	$ 291.3	$ 204.3
Other Electric Revenues	0.3	0.3	—
Other Operating Revenues	0.1	0.3	0.8
Sales to Affiliates	812.9	555.5	588.3
Provision for Rate Refund	(5.2)	(43.3)	(26.7)
Total Revenues AEP Transmission Holdco Segment	$ 1,073.2	$ 804.1	$ 766.7
Generation & Marketing Segment			
Generation Revenues			
Affiliated	$ —	$ —	$ —
Nonaffiliated	264.4	431.5	528.5

Renewable Generation			
Affiliated	—	—	—
Nonaffiliated	77.7	44.5	33.4
Retail, Trading and Marketing			
Affiliated	135.7	122.2	103.7
Nonaffiliated	1,379.8	1,342.1	1,209.5
Total Revenues Generation & Marketing Segment	$ 1,857.6	$ 1,940.3	$ 1,875.1

AEP Texas

Description	2019	2018	2017
	Years Ended December 31,		
	(in millions)		
Retail Revenues			
Residential Sales	$ 588.9	$ 594.6	$ 573.9
Commercial Sales	424.0	426.6	431.0
Industrial Sales	133.3	131.0	121.9
Other Retail Sales	30.8	30.1	30.0
Total Retail Revenues (a)	1,177.0	1,182.3	1,156.8
Wholesale Revenues			
Transmission	379.2	313.4	293.8
Other Electric Revenues	24.4	21.9	20.8
Provision for Rate Refund	(34.7)	(31.3)	(1.1)
Total Electric Transmission and Distribution Revenues	1,545.9	1,486.3	1,470.3
Sales to Affiliates	160.5	105.2	65.7
Other Revenues	2.9	3.8	2.4
Total Revenues	$ 1,709.3	$ 1,595.3	$ 1,538.4

AEPTCo

Description	2019	2018	2017
	Years Ended December 31,		
	(in millions)		
Transmission Revenues	$ 217.2	$ 212.8	$ 167.9
Other Electric Revenues	0.3	0.3	—
Other Operating Revenues	0.1	0.2	0.8
Sales to Affiliates	806.7	598.9	580.5
Provision for Rate Refund	(2.9)	(36.1)	(26.0)
Total Revenues	$ 1,021.4	$ 776.1	$ 723.2

APCo

Description	2019	2018	2017
	Years Ended December 31,		
	(in millions)		
Retail Revenues			
Residential Sales	$ 1,272.3	$ 1,372.1	$ 1,242.8
Commercial Sales	562.2	596.3	584.2
Industrial Sales	594.5	620.7	640.8
PJM Net Charges	(0.2)	(0.2)	(0.4)
Other Retail Sales	75.6	79.5	78.0
Total Retail Revenues (a)	2,504.4	2,668.4	2,545.4
Wholesale Revenues			
Off-system Sales	124.9	116.4	126.8
Transmission	57.0	56.3	57.1
Total Wholesale Revenues	181.9	172.7	183.9
Other Electric Revenues	32.3	31.1	33.4
Provision for Rate Refund	(10.4)	(95.1)	(13.7)
Total Electric Generation, Transmission and Distribution Revenues	2,708.2	2,777.1	2,749.0
Sales to Affiliates	205.3	181.4	172.0
Other Revenues	11.2	9.0	13.2
Total Revenues	$ 2,924.7	$ 2,967.5	$ 2,934.2

I&M

Description	Years Ended December 31, 2019	2018	2017
		(in millions)	
Retail Revenues			
Residential Sales	$ 730.9	$ 736.5	$ 620.9
Commercial Sales	494.9	489.3	438.8
Industrial Sales	551.4	570.6	522.0
PJM Net Charges	0.1	0.2	(1.0)
Other Retail Sales	7.3	7.2	7.1
Total Retail Revenues (a)	1,784.6	1,803.8	1,587.8
Wholesale Revenues			
Off-system Sales	406.4	459.3	431.2
Transmission	19.3	18.4	17.2
Total Wholesale Revenues	425.7	477.7	448.4
Other Electric Revenues	14.4	15.7	13.5
Provision for Rate Refund	(2.6)	(24.6)	(7.2)
Total Electric Generation, Transmission and Distribution Revenues	2,222.1	2,272.6	2,042.5
Sales to Affiliates	73.9	85.5	64.4
Other Revenues	10.7	12.6	14.3
Total Revenues	$ 2,306.7	$ 2,370.7	$ 2,121.2

OPCo

Description	Years Ended December 31, 2019	2018	2017
		(in millions)	
Retail Revenues			
Residential Sales	$ 1,495.6	$ 1,619.0	$ 1,511.3
Commercial Sales	724.9	840.1	774.8
Industrial Sales	293.2	386.2	367.2
Other Retail Sales	12.9	13.0	13.2
Total Retail Revenues (a)	2,526.6	2,858.3	2,666.5
Wholesale Revenues			
Off-system Sales	93.0	119.3	100.5
Transmission	58.5	61.4	65.8
Total Wholesale Revenues	151.5	180.7	166.3
Other Electric Revenues	34.2	32.7	31.0
Provision for Rate Refund	47.2	(37.9)	(10.3)
Total Electricity, Transmission and Distribution Revenues	2,759.5	3,033.8	2,853.5
Sales to Affiliates	27.3	21.0	24.4
Other Revenues	10.8	8.6	6.0
Total Revenues	$ 2,797.6	$ 3,063.4	$ 2,883.9

PSO

Description	Years Ended December 31, 2019	2018	2017
		(in millions)	
Retail Revenues			
Residential Sales	$ 636.1	$ 668.5	$ 601.4
Commercial Sales	377.3	401.1	387.7
Industrial Sales	296.5	308.5	284.0
Other Retail Sales	80.7	84.5	81.1
Total Retail Revenues (a)	1,390.6	1,462.6	1,354.2

Wholesale Revenues			
Off-system Sales	39.5	36.3	13.9
Transmission	31.9	47.4	42.3
Total Wholesale Revenues	71.4	83.7	56.2
Other Electric Revenues	9.6	10.3	8.5
Provision for Rate Refund	(2.0)	(19.0)	(1.4)
Total Electric Generation, Transmission and Distribution Revenues	1,469.6	1,537.6	1,417.5
Sales to Affiliates	6.1	5.4	4.3
Other Revenues	6.1	4.3	5.4
Total Revenues	$ 1,481.8	$ 1,547.3	$ 1,427.2

SWEPCo

Description	Years Ended December 31, 2019	2018	2017
		(in millions)	
Retail Revenues			
Residential Sales	$ 645.3	$ 666.0	$ 597.0
Commercial Sales	490.6	502.6	487.0
Industrial Sales	342.3	346.2	336.9
Other Retail Sales	9.1	8.9	8.8
Total Retail Revenues (a)	1,487.3	1,523.7	1,429.7
Wholesale Revenues			
Off-system Sales	194.7	216.8	251.3
Transmission	72.6	94.2	71.7
Total Wholesale Revenues	267.3	311.0	323.0
Other Electric Revenues	20.6	20.9	20.4
Provision for Rate Refund	(30.6)	(63.7)	(21.0)
Total Electric Generation, Transmission and Distribution Revenues	1,744.6	1,791.9	1,752.1
Sales to Affiliates	4.9	28.4	25.9
Other Revenues	1.4	1.6	1.9
Total Revenues	$ 1,750.9	$ 1,821.9	$ 1,779.9

(a) 2018 and 2017 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.

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs. Short-term debt may also be used to finance acquisitions, construction and redemption or repurchase of outstanding securities until such needs can be financed with long-term debt. In recent history, short-term funding needs have been provided for by cash on hand and AEP's commercial paper program. Funds are made available to subsidiaries under the AEP corporate borrowing program. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity. See "Financial Condition" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

AEP's revolving credit agreement (which backstops the commercial paper program) includes covenants and events of default typical for this type of facility, including a maximum debt/capital test. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of its 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 the credit agreement. As of December 31, 2019, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreement. A voluntary bankruptcy or insolvency of AEP or one of its significant subsidiaries would be considered an immediate termination event. See "Financial Condition" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as securitization financings and leasing arrangements, including the leasing of coal transportation equipment and facilities.

ENVIRONMENTAL AND OTHER MATTERS

General

AEP subsidiaries are currently subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. The environmental issues that management believes are potentially material to the AEP System are outlined below.

Clean Water Act Requirements

Operations for AEP subsidiaries are subject to the Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits and regulates systems that withdraw surface water for use in power plants. In 2014, the Federal EPA issued a final rule setting forth standards for water withdrawals at existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. The standards affect all plants withdrawing more than two million gallons of cooling water per day. Compliance with this standard is required within eight years of the effective date of the final rule.

In November 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for electricity generating facilities. The rule establishes limits on Flue Gas Desulfurization 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. In January 2020, the Federal EPA issued a final rule revising the scope of the "waters of the United States" subject to Clean Water Act regulation. See "Environmental Issues - Clean Water Act Regulations" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

Coal Ash Regulation

AEP's operations produce a number of different coal combustion by-products, including fly ash, bottom ash, gypsum and other materials. A Federal EPA rule regulates the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The rule requires certain standards for location, groundwater monitoring and dam stability to be met at landfills and certain surface impoundments at operating facilities. If existing disposal facilities cannot meet these standards, they will be required to close. See "Environmental Issues - Coal Combustion Residual Rule" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting AEP's power plants are described below. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Acid Rain Program

The CAA includes a cap-and-trade emission reduction program for SO_2 emissions from power plants and requirements for power plants to reduce NO_x emissions through the use of available combustion controls, collectively called the Acid Rain Program. AEP continues to meet its obligations under the Acid Rain Program through the installation of controls, use of alternate fuels and participation in the emissions allowance markets.

National Ambient Air Quality Standards (NAAQS)

The CAA requires the Federal EPA to review the available scientific data for criteria pollutants periodically and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra safety margin. The Federal EPA also can list additional pollutants and develop concentration levels for them. These concentration levels are known as NAAQS.

Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (non-attainment areas). Each state must develop a SIP to bring non-attainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. As the Federal EPA reviews the NAAQS and establishes new concentration levels, the attainment status of areas can change and states may be required to develop new SIPs. See "Environmental Issues - Clean Air Act Requirements" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

Hazardous Air Pollutants (HAP)

The CAA also requires the Federal EPA to investigate HAP emissions from the electric utility sector and submit a report to Congress to determine whether those emissions should be regulated. In 2011, the Federal EPA issued a rule setting Maximum Achievable Control Technology standards for new and existing coal and oil-fired utility units and New Source Performance Standards for emissions from new and modified power plants. In 2014, the U.S. Supreme Court determined that the Federal EPA acted unreasonably in refusing to consider costs in determining if it was appropriate and necessary to regulate HAP emissions from electric generating units. The Federal EPA has engaged in additional rulemaking activity but the 2011 rule remains in effect. See "Environmental Issues - Hazardous Air Pollutants" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

Regional Haze

The CAA establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment of visibility in these protected areas. In 2005, the Federal EPA issued its Clean Air Visibility Rule, detailing how the CAA's best available retrofit technology requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants.

PSO executed a settlement with the Federal EPA and the State of Oklahoma to comply with Regional Haze program requirements in Oklahoma, and the settlement is now codified in the Oklahoma SIP and approved by the Federal EPA. The Federal EPA disapproved portions of the Arkansas and Texas SIPs, and finalized FIPs for both states. Arkansas submitted and received approval of a revised SIP, and EPA developed a revised FIP for Texas. See "Environmental Issues - Clean Air Act Requirements" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

Climate Change

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. In 2019, AEP announced revised 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, regulations, grid reliability and resiliency, and reflect 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 an 80% or more reduction of CO_2 emissions from AEP generating facilities from 2000 levels by 2050. AEP's total estimated CO_2 emissions in 2019 were approximately 58 million metric tons, a 65% reduction from AEP's 2000 CO_2 emissions.

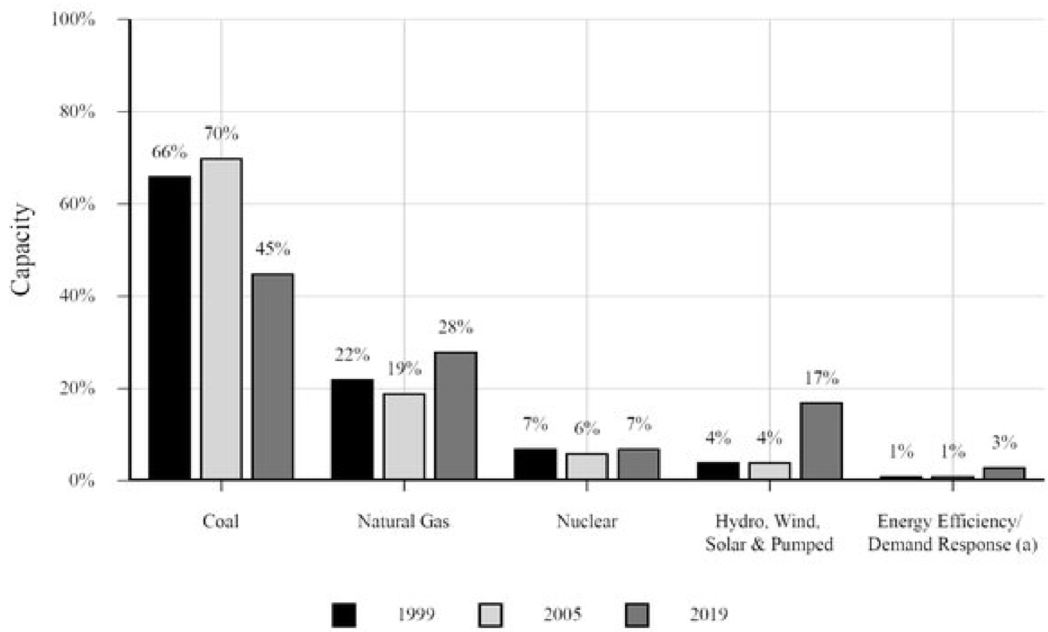
The Federal EPA has taken action to regulate CO_2 emissions from new and existing fossil fueled electric generating units under the existing provisions of the CAA. The Clean Power Plan was adopted in October 2015 but the U.S. Supreme Court issued a stay of its implementation, including all of the deadlines for submission of initial or final state plans. The Federal EPA issued a proposal in 2017 to repeal the Clean Power Plan and finalized the repeal in 2019. In 2018 the Federal EPA issued a proposal to revise the standards for new and modified sources. In 2019, the Federal EPA finalized new guidelines for states to use to develop CO_2 performance standards for coal–fired generating units. See "Environmental Issues - Climate Change, CO_2 Regulation and Energy Policy" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

Management expects emissions to continue to decline over time as AEP diversifies generating sources and operates fewer coal units. The projected decline in coal-fired generation is due to a number of factors, including the ongoing cost of operating older units, the relative cost of coal and natural gas as fuel sources, increasing environmental regulations requiring significant capital investments and changing commodity market fundamentals.

Transforming AEP's Generation Fleet

The electric utility industry is in the midst of an historic transformation, driven by changing customer needs, policy demands, demographics, competitive offerings, technologies and commodity prices. AEP is also transforming to be more agile and customer-focused as a valued provider of energy solutions. AEP's long-term commitment to reduce CO_2 emissions reflects the current direction of the company's resource plans to meet those needs. AEP's exposure to carbon regulation has been greatly reduced over the last several years. From 2000 to 2019, AEP's CO_2 emissions declined 65%. In 2019, coal represented 45% of AEP's generating capacity, compared with 70% in 2005. Management expects the percentage of AEP's generating resources fueled by coal will continue to decline. Transforming AEP's generation portfolio to include, where there is regulatory support, more renewable energy and focusing on the efficient use of energy, demand response, distributed resources and technology solutions to more efficiently manage the grid over time is part of this strategy.

The graph below summarizes AEP's generation capacity by resource type for the years 1999, 2005 and 2019:



(a) Energy Efficiency/Demand Response represents avoided capacity rather than physical assets.

Renewable Sources of Energy

The states AEP serves, other than Kentucky, West Virginia and Tennessee, have established mandatory or voluntary programs to increase the use of energy efficiency, alternative energy or renewable energy sources.

As of December 31, 2019, AEP's regulated utilities had long-term contracts for 2,750 MWs of wind, 80 MWs of hydro, and 10 MWs of solar power delivering renewable energy to the companies' customers. In addition, I&M owns four solar projects that make up I&M's 16 MW Clean Energy Solar Pilot Project. Management actively manages AEP's compliance position and is on pace to meet the relevant requirements or benchmarks in each applicable jurisdiction.

In July 2019, PSO and SWEPCo submitted filings before their respective commissions for 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 54.5% of the project, which will cost approximately $2 billion. Two wind facilities, totaling 1,286 MWs, would qualify for 80% of the federal Production Tax Credits (PTCs) with year-end 2021 in-service dates. The third wind facility (199 MWs) would qualify for 100% of the PTCs 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. In December 2019, PSO reached a joint stipulation and settlement agreement with the OCC, Oklahoma Attorney General's office and customer groups. In January 2020, SWEPCo reached a joint settlement agreement with the APSC, Arkansas Attorney General's office and Walmart, Inc. Hearings are scheduled for the first quarter of 2020. PSO and SWEPCo are seeking regulatory approvals by July 2020.

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. In addition to gradually reducing AEP's reliance on coal-fueled generating units, the growth of renewables and natural gas helps AEP to maintain a diversity of generation resources.

The integrated resource plans filed with state regulatory commissions by AEP's regulated utility subsidiaries reflect AEP's renewable strategy to balance reliability and cost with customers' desire for clean energy in a carbon-constrained world. AEP has committed significant capital investments to modernize the electric grid and integrate these new resources. Transmission assets of the AEP System interconnect approximately 11,900 MWs of renewable energy resources. AEP's transmission development initiatives are designed to facilitate the interconnection of additional renewable energy resources.

AEP Energy Supply, LLC is a holding company with several divisions, including AEP Renewables and AEP OnSite Partners.

AEP Renewables develops, owns and operates utility scale renewable projects backed with long-term contracts with creditworthy counterparties throughout the United States. AEP Renewables works directly with stakeholders to ensure that customers have clean, sustainable renewable energy to meet their environmental goals. As of December 31, 2019, AEP Renewables owned projects operating in 11 states, including approximately 1,212 MWs of installed wind capacity and 90 MWs of installed solar capacity. These figures include the 2019 addition of 724 MWs of wind generation and battery assets located in several states acquired from Sempra Renewables LLC and the 75% interest, or 227 MWs, of Santa Rita East wind generation located in west Texas. In October 2019, AEP Renewables entered into an agreement to construct Flat Ridge 3, a wind farm in Kansas. The 128 MW facility is expected to reach commercial operation before the end of 2020.

AEP OnSite Partners works directly with wholesale and large retail customers to provide tailored solutions to reduce their energy costs based upon market knowledge, innovative applications of technology and deal structuring capabilities. AEP OnSite Partners targets opportunities in distributed solar, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other energy solutions that create value for customers. AEP OnSite Partners pursues and develops behind the meter projects with creditworthy customers. As of December 31, 2019, AEP OnSite Partners owned projects located in 17 states, including approximately 119 MWs of installed solar capacity, and approximately 28 MWs of solar projects under construction.

Competitive Renewable Generation Facilities

Size of Energy Resource	AEP Energy Supply, LLC Division	Renewable Energy Resource	Location	In-Service or Under Construction
1,212 MW	AEP Renewables	Wind	Eight states (a)	In-service
128 MW	AEP Renewables	Wind	Kansas	Under Construction
20 MW	AEP Renewables	Solar	California	In-service
20 MW	AEP Renewables	Solar	Utah	In-service
50 MW	AEP Renewables	Solar	Nevada	In-service
119 MW	AEP OnSite Partners	Solar	Fifteen states (b)	In-service
28 MW	AEP OnSite Partners	Solar	Three states (c)	Under Construction

(a) Colorado, Hawaii, Indiana, Kansas, Michigan, Minnesota, Pennsylvania, and Texas.
(b) California, Colorado, Florida, Hawaii, Iowa, Minnesota, Nebraska, New Hampshire, New Jersey, New Mexico, New York, Ohio, Rhode Island, Texas and Vermont.
(c) Illinois, New Mexico and Ohio.

End Use Energy Efficiency

AEP has reduced energy consumption and peak demand through the introduction of additional energy efficiency and demand response programs. These programs, commonly referred to as demand side management, were implemented in jurisdictions where appropriate cost recovery was available. AEP's operating companies' programs have reduced annual consumption by over 9 million MWhs and peak demand by approximately 2,806 MWs since 2008. AEP estimates that its operating companies spent approximately $1.5 billion during that period to achieve these levels.

Energy efficiency and demand reduction programs have received regulatory support in most of the states AEP serves. Appropriate cost recovery will be essential for AEP operating companies to continue and expand these consumer offerings. Appropriate recovery of program costs, lost revenues and an opportunity to earn a reasonable return ensures that energy efficiency programs are considered equally with supply side investments. As AEP continues to transition to a cleaner, more efficient energy future, energy efficiency and demand response programs will continue to play an important role in how the company serves its customers. AEP believes its experience providing robust energy efficiency programs in several states positions the company to be a cost-effective provider of these programs as states develop their implementation plans.

Corporate Governance

In response to environmental issues and in connection with its assessment of AEP's strategic plan, the Board of Directors continually reviews the risks posed by new environmental rules and requirements that could accelerate the retirement of coal-fired generation assets. The Board of Directors is informed of any new environmental regulations and proposed regulation or legislation that would significantly affect AEP. The Board's Committee on Directors and Corporate Governance oversees AEP's annual Corporate Accountability Report, which includes information about AEP's environmental, social, governance and financial performance. AEP set CO_2 emission reduction goals in 2018 after considering input from corporate governance outreach effort with shareholders.

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 has made significant progress in reducing CO_2 emissions from its power generation fleet and expects its emissions to continue to decline. AEP's aspirational emissions goal is zero CO_2 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.

Other Environmental Issues and Matters

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 imposes costs for environmental remediation upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites. See "The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation" section of Note 6 included in the 2019 Annual Report for additional information.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2017, 2018 and 2019 and the current estimate for 2020 are shown below. These investments include both environmental as well as other related spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends and the ability to access capital. In addition to the amounts set forth below, AEP expects to make substantial investments in future years in connection with the modification and addition at generation plants' facilities for environmental quality controls. Such future investments are needed in order to comply with air and water quality standards that have been adopted and have deadlines for compliance after 2019 or have been proposed and may be adopted. Future investments could be significantly greater if emissions reduction requirements are accelerated or otherwise become more stringent. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. AEP typically recovers costs of complying with environmental standards from customers through rates in regulated jurisdictions. Failure to recover these costs could reduce future net income and cash flows and possibly harm AEP's financial condition. See "Environmental Issues" section of Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 6 - Commitments, Guarantees and Contingencies included in the 2019 Annual Report for additional information.

Historical and Projected Environmental Investments

	2017 Actual	2018 Actual	2019 Actual	2020 Estimate (b)
	(in millions)			
AEP (a)	$ 135.9	$ 115.6	$ 167.2	$ 176.1
APCo	25.6	20.4	23.8	37.3
I&M	41.9	31.1	56.4	33.4
PSO	0.6	—	—	6.0
SWEPCo	11.7	14.1	10.5	40.1

(a) Includes expenditures of the subsidiaries shown and other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.
(b) Estimated amounts are exclusive of debt AFUDC.

Management continues to refine the cost estimates of complying with air and water quality standards and other impacts of the environmental proposals. The following cost estimates for the years 2020 through 2026 will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. These cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for SIPs or FIPs that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired, replaced or sold, including the type and amount of such replacement capacity and (g) other factors. Management's current ranges of estimates of new major environmental investments beginning in 2020, exclusive of debt AFUDC, are set forth below:

	Projected (2020 - 2026) Environmental Investment	
Company	**Low**	**High**
	(in millions)	
AEP	$ 500	$ 1,000
APCo	125	230
I&M	45	85
PSO	20	30
SWEPCo	150	305

BUSINESS SEGMENTS

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 are as follows:

- Vertically Integrated Utilities
- Transmission and Distribution Utilities
- AEP Transmission Holdco
- Generation & Marketing

The remainder of AEP's activities is presented as Corporate and Other, which is not considered a reportable segment. See Note 9 - Business Segments included in the 2019 Annual Report for additional information on AEP's segments.

VERTICALLY INTEGRATED UTILITIES

GENERAL

AEP's vertically integrated utility operations are engaged in the 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. AEPSC, as agent for AEP's public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities on behalf of each of these subsidiaries.

ELECTRIC GENERATION

Facilities

As of December 31, 2019, AEP's vertically integrated public utility subsidiaries owned or leased approximately 22,000 MWs of domestic generation. See Item 2 – Properties for more information regarding the generation capacity of vertically integrated public utility subsidiaries.

Fuel Supply

The following table shows the owned and leased generation sources by type (including wind purchase agreements), on an actual net generation (MWhs) basis, used by the Vertically Integrated Utilities:

	2019	2018	2017
Coal and Lignite	54%	58%	61%
Nuclear	19%	18%	18%
Natural Gas	16%	14%	11%
Renewables	11%	10%	10%

A price increase/decrease in one or more fuel sources relative to other fuels, as well as the addition of renewable resources, may result in the decreased/increased use of other fuels. AEP's overall 2019 fossil fuel costs for the Vertically Integrated Utilities increased 2.4% on a dollar per MMBtu basis from 2018.

Coal and Lignite

AEP's Vertically Integrated Utilities procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers, marketers and coal trading firms. Coal consumption in 2019 decreased approximately 18% from 2018 mainly due to lower dispatching of coal generation from weaker power market prices.

Management believes that the Vertically Integrated Utilities will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. Through subsidiaries, AEP owns, leases or controls more than 4,004 railcars, 468 barges, 8 towboats and a coal handling terminal with approximately 18 million tons of annual capacity to move and store coal for use in AEP generating facilities.

Spot market prices for coal started to weaken in the second half of 2019. The decreased spot coal prices reflect lower demand for domestic and export coal. AEP's strategy for purchasing coal includes layering in supplies over time. The price impact of this process is reflected in subsequent periods and can occasionally cause current spot market prices to be trending opposite to the price of coal delivered. The price paid for coal delivered in 2019 increased approximately 6% from 2018.

The following table shows the amount of coal and lignite delivered to the Vertically Integrated Utilities' plants during the past three years and the average delivered price of coal purchased by the Vertically Integrated Utilities:

	2019	2018	2017
Total coal delivered to the plants (millions of tons)	30.4	29.0	29.3
Average cost per ton of coal delivered	$ 45.85	$ 43.21	$ 44.24

The coal supplies at the Vertically Integrated Utilities plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, availability of acceptable coals, labor issues and weather conditions, which may interrupt production or deliveries. As of December 31, 2019, the Vertically Integrated Utilities' coal inventory was approximately 54 days of full load burn. While inventory targets vary by plant and are changed as necessary, the current coal inventory target for the Vertically Integrated Utilities is approximately 30 days of full load burn.

Natural Gas

The Vertically Integrated Utilities consumed approximately 117 billion cubic feet of natural gas during 2019 for generating power. This represents an increase of 5% from 2018. Total gas consumption for the Vertically Integrated Utilities was higher year over year primarily due to lower natural gas prices. Several of AEP's natural gas-fired power plants are connected to at least two pipelines which allow greater access to competitive supplies and improve delivery reliability. A portfolio of term, monthly, seasonal and daily supply and transportation agreements provide natural gas requirements for each plant, as appropriate. AEP's natural gas supply agreements are entered into on a competitive basis and based on market prices.

The following table shows the amount of natural gas delivered to the Vertically Integrated Utilities' plants during the past three years and the average delivered price of natural gas purchased by the Vertically Integrated Utilities.

	2019	2018	2017
Total natural gas delivered to the plants (billion of cubic feet)	117.0	111.6	86.3
Average price per MMBtu of purchased natural gas	$ 2.64	$ 3.26	$ 3.37

Nuclear

I&M has made commitments to meet the current nuclear fuel requirements of the Cook Plant. I&M has made and will make purchases of uranium in various forms in the spot, short-term and mid-term markets. I&M also continues to finance its nuclear fuel through leasing.

For purposes of the storage of high-level radioactive waste in the form of SNF, I&M completed modifications to its SNF storage pool in the early 1990's. I&M entered into an agreement to provide for onsite dry cask storage of SNF to permit normal operations to continue. I&M is scheduled to conduct further dry cask loading and storage projects on an ongoing periodic basis.

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial commitment to dispose of SNF and decommission and decontaminate the plant safely. The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. The most recent decommissioning cost study was completed in 2018. The estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant was $2 billion in 2018 non-discounted dollars, with additional ongoing estimated costs of $6 million per year for post decommissioning storage of SNF and an eventual estimated cost of $37 million for the subsequent decommissioning of the spent fuel storage facility, also in 2018 non-discounted dollars. As of December 31, 2019 and 2018, the total decommissioning trust fund balance for the Cook Plant was approximately $2.7 billion and $2.2 billion, respectively. The balance of funds available to eventually decommission Cook Plant will differ based on contributions and investment returns. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

- Escalation of various cost elements (including, but not limited to, general inflation and the cost of energy).
- Further development of regulatory requirements governing decommissioning.
- Technology available at the time of decommissioning differing significantly from that assumed in studies.
- Availability of nuclear waste disposal facilities.
- Availability of a United States Department of Energy facility for permanent storage of SNF.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections. AEP will seek recovery from customers through regulated rates if actual decommissioning costs exceed projections. See the "Nuclear Contingencies" section of Note 6 - Commitments, Guarantees and Contingencies included in the 2019 Annual Report for information with respect to nuclear waste and decommissioning.

Low-Level Radioactive Waste

The Low-Level Waste Policy Act of 1980 mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan does not currently have a disposal site for such waste available. I&M cannot predict when such a site may be available. However, the states of Utah and Texas have licensed low level radioactive waste disposal sites which currently accept low level radioactive waste from Michigan waste generators. There is currently no set date limiting I&M's access to either of these facilities. The Cook Plant has a facility onsite designed specifically for the storage of low level radioactive waste. In the event that low level radioactive waste disposal facility access becomes unavailable, it can be stored onsite at this facility.

Counterparty Risk Management

The Vertically Integrated Utilities segment also sells power and enters into related energy transactions with wholesale customers and other market participants. As a result, counterparties and exchanges may require cash or cash related instruments to be deposited on transactions as margin against open positions. As of December 31, 2019, counterparties posted approximately $13 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries posted approximately $24 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See the "Quantitative and Qualitative Disclosures About Market Risk" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

Certain Power Agreements

I&M

The UPA between AEGCo and I&M, dated March 31, 1982, provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay a demand charge for the right to receive such power (and an energy charge for any associated energy taken by I&M). The agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant have expired (currently December 2022) unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a UPA between AEGCo and KPCo, AEGCo sells KPCo 30% of the capacity (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo the amounts that I&M would have paid AEGCo under the terms of the UPA between AEGCo and I&M for such entitlement. The KPCo UPA expires in December 2022.

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP in OVEC is 43.47%. Parent owns 39.17% and OPCo owns 4.3%. Under the Inter-Company Power Agreement (ICPA), which defines the rights of the owners and sets the power participation ratio of each, the sponsoring companies are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,400 MWs) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. The ICPA terminates in June 2040. The proceeds from charges by OVEC to sponsoring companies under the ICPA based on their prower participation ratios are designed to be sufficient for OVEC to meet its operating expenses and fixed costs. OVEC's Board of Directors, as elected by AEP and the other owners, has authorized environmental investments related to their ownership interests, with resulting expenses (including for related debt and interest thereon) included in charges under the ICPA. OVEC financed capital expenditures totaling $1.3 billion in connection with flue gas desulfurization projects and the associated scrubber waste disposal landfills at its two generation plants through debt issuances, including tax-advantaged debt issuances. Both OVEC generation plants are operating with the new environmental controls in service. OPCo attempted to assign its rights and obligations under the ICPA to an affiliate as part of its transfer of its generation assets and liabilities in keeping with corporate separation required by Ohio law. OPCo failed to obtain the consent to assignment from the other owners of OVEC and therefore filed a request with the PUCO seeking authorization to maintain its ownership of OVEC. In December 2013, the PUCO approved OPCo's request, subject to the condition that energy from the OVEC entitlements are sold into the day-ahead or real-time PJM energy markets, or on a forward basis through a bilateral arrangement. In November 2016, the PUCO approved OPCo's request to approve a cost-based purchased power agreement (PPA) rider, effective in January 2017, that would initially be based upon OPCo's contractual entitlement under the ICPA which is approximately 20% of OVEC's capacity. In January 2020, provisions enacted as part of Ohio Am. Sub. H.B. 6 went into effect that replace the PPA rider and enable OPCo to continue recovering the net cost associated with the ICPA, including any additional contractual entitlement received as a result of the FirstEnergy Solutions (FES) bankruptcy, through 2030.

In March 2018, FES, with an aggregate power participation ratio of approximately 5% under the ICPA, filed bankruptcy. In July 2018, the Bankruptcy Court granted FES's motion to reject the ICPA. OVEC appealed this decision in the United States Court of Appeals for the Sixth Circuit and in December 2019 the Sixth Circuit remanded the rejection of the ICPA back to the Bankruptcy Court for further consideration based on reversing the Bankruptcy Court's application of the business judgment standard in rejecting the ICPA. If OVEC does not have sufficient funds to honor its payment obligations, there is risk that APCo, I&M and/or OPCo may need to make payments in addition to their power participation ratio payments. Further, if OVEC's indebtedness is accelerated for any reason, there is risk that APCo, I&M and/or OPCo may be required to pay some or all of such accelerated indebtedness in amounts equal to their aggregate power participation ratio of 43.47%. The foregoing and other related actions have adversely impacted the credit ratings of OVEC.

ELECTRIC DELIVERY

General

Other than AEGCo, AEP's vertically integrated public utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 – Properties for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold to retail customers of AEP's vertically integrated public utility subsidiaries in their service territories. These sales are made at rates approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See Item 1. Business – Vertically Integrated Utilities – Regulation – Rates. The FERC regulates and approves the rates for both wholesale transmission transactions and wholesale generation contracts. The use and the recovery of costs associated with the transmission assets of the AEP vertically integrated public utility subsidiaries are subject to the rules, principles, protocols and agreements in place with PJM and SPP, and as approved by the FERC. See Item 1. Business – Vertically Integrated Utilities – Regulation – FERC. As discussed below, some transmission services also are separately sold to nonaffiliated companies.

Other than AEGCo, AEP's vertically integrated public utility subsidiaries hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service within a specific territory. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business. For a discussion of competition in the sale of power, see Item 1. Business – Vertically Integrated Utilities – Competition.

Transmission Agreement (TA)

APCo, I&M, KGPCo, KPCo and WPCo own and operate transmission facilities that are used to provide transmission service under the PJM OATT and are parties to the TA. OPCo, which is a subsidiary in AEP's Transmission and Distribution Utilities segment that provides transmission service under the PJM OATT, is also a party to the TA. The TA defines how the parties to the agreement share the revenues associated with their transmission facilities and the costs of transmission service provided by PJM. The TA has been approved by the FERC.

TCA and OATT

PSO, SWEPCo and AEPSC are parties to the TCA. Under the TCA, a coordinating committee is charged with the responsibility of (a) overseeing the coordinated planning of the transmission facilities of the parties to the agreement, including the performance of transmission planning studies, (b) the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and (c) compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff. Pursuant to the TCA, AEPSC has responsibility for monitoring the reliability of their transmission systems and administering the OATT on behalf of the other parties to the agreement. The TCA also provides for the allocation among the parties of revenues collected for transmission and ancillary services provided under the OATT. These allocations have been determined by the FERC-approved OATT for the SPP.

Regional Transmission Organizations

AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM, and PSO and SWEPCo are members of SPP (both FERC-approved RTOs). RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not.

REGULATION

General

AEP's vertically integrated public utility subsidiaries' retail rates and certain other matters are subject to traditional cost-based regulation by the state utility commissions. AEP's vertically integrated public utility subsidiaries are also subject to regulation by the FERC under the Federal Power Act with respect to wholesale power and transmission service transactions. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its vertically integrated public utility subsidiaries are also subject to the regulatory provisions of, much of the Energy Policy Act of 2005, which is administered by the FERC.

Rates

Historically, state utility commissions have established electric service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. A utility's cost of service generally reflects its operating expenses, including operation and maintenance expense, depreciation expense and taxes. State utility commissions periodically adjust rates pursuant to a review of (a) a utility's adjusted revenues and expenses during a defined test period and (b) such utility's level of investment. Absent a legal limitation, such as a law limiting the frequency of rate changes or capping rates for a period of time, a state utility commission can review and change rates on its own initiative. Some states may initiate reviews at the request of a utility, customer, governmental or other representative of a group of customers. Such parties may, however, agree with one another not to request reviews of or changes to rates for a specified period of time.

Public utilities have traditionally financed capital investments until the new asset is placed in service. Provided the asset was found to be a prudent investment, it was then added to rate base and entitled to a return through rate recovery. Given long lead times in construction, the high costs of plant and equipment and volatile capital markets, management actively pursues strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process. These options include pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates.

The rates of AEP's vertically integrated public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). Historically, the state regulatory frameworks in the service area of the AEP vertically integrated public utility subsidiaries reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes.

The following state-by-state analysis summarizes the regulatory environment of certain major jurisdictions in which AEP's vertically integrated public utility subsidiaries operate. Several public utility subsidiaries operate in more than one jurisdiction. See Note 4 - Rate Matters included in the 2019 Annual Report for more information regarding pending rate matters.

Indiana

I&M provides retail electric service in Indiana at bundled rates approved by the IURC, with rates set on a cost-of-service basis. Indiana provides for timely fuel and purchased power cost recovery through a fuel cost recovery mechanism.

Oklahoma

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs are recovered or refunded by applying fuel adjustment and other factors to retail kilowatt-hour sales.

Virginia

APCo currently provides retail electric service in Virginia at unbundled generation and distribution rates approved by the Virginia SCC. Virginia generally allows for timely recovery of fuel costs through a fuel adjustment clause. In addition to base rates and fuel cost recovery, APCo is permitted to recover a variety of costs through rate adjustment clauses including transmission services provided at OATT rates based on rates established by the FERC.

West Virginia

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a combined cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses.

FERC

The FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP's vertically integrated public utility subsidiaries to provide open access transmission service at FERC-approved rates, and AEP has approved cost-based formula transmission rates on file at the FERC. The FERC also regulates unbundled transmission service to retail customers. In addition, the FERC regulates the sale of power for resale in interstate commerce by (a) approving contracts for wholesale sales to municipal and cooperative utilities and (b) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. AEP's vertically integrated public utility subsidiaries have market-based rate authority from the FERC, under which much of their wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an Open Access Same-time Information System, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees. Additionally, the vertically integrated public utility subsidiaries are subject to reliability standards promulgated by the North American Electric Reliability Corporation, with the approval of the FERC.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM. PSO and SWEPCo are members of SPP.

The FERC has jurisdiction over the issuances of securities of most of AEP's public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system.

COMPETITION

Other than AEGCo, AEP's vertically integrated public utility subsidiaries generate, transmit and distribute electricity to retail customers of AEP's vertically integrated public utility subsidiaries in their service territories. These sales are made at rates approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC, and are not subject to competition from other vertically integrated public utilities. Other than AEGCo, AEP's vertically integrated public utility subsidiaries hold franchises or other rights that effectively grant the exclusive ability to provide electric service in various municipalities and regions in their service areas.

AEP's vertically integrated public utility subsidiaries compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil, renewables and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize alternative sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they currently maintain a competitive position.

Changes in regulatory policies and advances in newer technologies for batteries or energy storage, fuel cells, microturbines, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production. The costs of photovoltaic solar cells in particular have continued to become increasingly competitive. The ability to maintain relatively low cost, efficient and reliable operations and to provide cost-effective programs and services to customers are significant determinants of AEP's competitiveness.

SEASONALITY

The consumption of electric power is generally seasonal. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of AEP's facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP's results of operations. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

TRANSMISSION AND DISTRIBUTION UTILITIES

GENERAL

This segment consists of the transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo. OPCo is engaged in the transmission and distribution of electric power to approximately 1,494,000 retail customers in Ohio. OPCo purchases energy and capacity at auction to serve generation service customers who have not switched to a competitive generation supplier. AEP Texas is engaged in the transmission and distribution of electric power to approximately 1,049,000 retail customers through REPs in west, central and southern Texas.

AEP's transmission and distribution utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 – Properties, for more information regarding the transmission and distribution lines. Transmission and distribution services are sold to retail customers of AEP's transmission and distribution utility subsidiaries in their service territories. These sales are made at rates approved by the PUCT for AEP Texas and by the PUCO and the FERC for OPCo. The FERC regulates and approves the rates for wholesale transmission transactions. As discussed below, some transmission services also are separately sold to nonaffiliated companies.

AEP's transmission and distribution utility subsidiaries hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business.

The use and the recovery of costs associated with the transmission assets of the AEP transmission and distribution utility subsidiaries are subject to the rules, protocols and agreements in place with PJM and ERCOT, and as approved by the FERC. In addition to providing transmission services in connection with power sales in their service areas, AEP's transmission and distribution utility subsidiaries also provide transmission services for nonaffiliated companies through RTOs.

Transmission Agreement

OPCo owns and operates transmission facilities that are used to provide transmission service under the PJM OATT; OPCo is a party to the TA with other utility subsidiary affiliates. The TA defines how the parties to the agreement share the revenues associated with their transmission facilities and the costs of transmission service provided by PJM. The TA has been approved by the FERC.

Regional Transmission Organizations

OPCo is a member of PJM, a FERC-approved RTO. RTOs operate, plan and control utility transmission assets to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not. AEP Texas is a member of ERCOT.

REGULATION

OPCo provides distribution and transmission services to retail customers within its service territory at cost-based rates approved by the PUCO or by the FERC. AEP Texas provides transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Transmission and distribution rates are established on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. The cost of service generally reflects operating expenses, including operation and maintenance expense, depreciation expense and taxes. Utility commissions periodically adjust rates pursuant to a review of: (a) a utility's adjusted revenues and expenses during a defined test period and (b) such utility's level of investment.

FERC

The FERC regulates rates for transmission of electric power, accounting and other matters. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates, and it has approved cost-based formula transmission rates on file at the FERC. The FERC also regulates unbundled transmission service to retail customers. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an Open Access Same-time Information System, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. Additionally, the transmission and distribution utility subsidiaries are subject to reliability standards as set forth by the North American Electric Reliability Corporation, with the approval of the FERC.

SEASONALITY

The delivery of electric power is generally seasonal. In many parts of the country, demand for power peaks during the hot summer months. In other areas, power demand peaks during the winter months. The pattern of this fluctuation may change due to the nature and location of AEP's transmission and distribution facilities. In addition, AEP transmission and distribution has historically delivered less power, and consequently earned less income, when weather conditions are milder. In Texas, and to a lesser extent, in Ohio, where there is residential decoupling, unusually mild weather in the future could diminish AEP's results of operations. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

AEP TRANSMISSION HOLDCO

GENERAL

AEPTHCo is a holding company for (a) AEPTCo, which is the direct holding company for the State Transcos and (b) AEP's Transmission Joint Ventures.

AEPTCo

AEPTCo wholly owns the State Transcos which are independent of, but respectively overlay, the following AEP electric utility operating companies: APCo, I&M, KPCo, OPCo, PSO, SWEPCo, and WPCo. The State Transcos develop, own, operate, and maintain their respective transmission assets. Assets of the State Transcos interconnect to transmission facilities owned by the aforementioned operating companies and nonaffiliated transmission owners within the footprints of PJM, MISO and SPP. APTCo, IMTCo, KTCo, OHTCo, and WVTCo are located within PJM. IMTCo also owns portions of the Greentown station assets located in MISO. OKTCo and SWTCo are located within SPP.

IMTCo, KTCo, OHTCo, OKTCo, and WVTCo own and operate transmission assets in their respective jurisdictions. The Virginia SCC and WVPSC granted consent for APCo and APTCo to enter into a joint license agreement that will support APTCo investment in the state of Tennessee. SWTCo does not currently own or operate transmission assets.

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. The State Transcos establish transmission rates each year through formula rate filings with the FERC. The rate filings calculate the revenue requirement needed to cover the costs of operation and debt service and to earn an allowed ROE. These rates are then included in an OATT for PJM, MISO and SPP.

The State Transcos own, operate, maintain and invest in transmission infrastructure in order to maintain and enhance system integrity and grid reliability, grid security, safety, reduce transmission constraints and facilitate interconnections of new generating resources and new wholesale customers, as well as enhance competitive wholesale electricity markets. A key part of AEP's business is replacing and upgrading transmission facilities, assets and components of the existing AEP System as needed to maintain reliability.

The State Transcos provide the capability to build, replace and upgrade existing facilities. As of December 31, 2019, the State Transcos had $8.4 billion of transmission and other assets in-service with plans to construct approximately $4.3 billion of additional transmission assets through 2022. Additional investment in transmission infrastructure is needed within PJM and SPP to maintain the required level of grid reliability, resiliency, security and efficiency and to address an aging transmission infrastructure. Additional transmission facilities will be needed based on changes in generating resources, such as wind or solar projects, generation additions or retirements, and additional new customer interconnections. The State Transcos will continue their investment to enhance physical and cyber security of assets, and are also investing in improving the telecommunication network that supports the operation and control of the grid.

AEPTHCO JOINT VENTURE INITIATIVES

AEP has established joint ventures with other electric utility companies for the purpose of developing, building, and owning transmission assets that seek to improve reliability and market efficiency and provide transmission access to remote generation sources in North America (Transmission Joint Ventures).

The Transmission Joint Ventures currently include:

Joint Venture Name	Location	Projected or Actual Completion Date	Owners (Ownership %)	Total Estimated/Actual Project Costs at Completion		Approved Return on Equity	
				(in millions)			
ETT	Texas (ERCOT)	(a)	Berkshire Hathaway Energy (50%) AEP (50%)	$ 3,376.1	(a)	9.6%	
Prairie Wind	Kansas	2014	Evergy, Inc. (50%) Berkshire Hathaway Energy (25%) AEP (25%)	158.0		12.8%	
Pioneer	Indiana	2018	Duke Energy (50%) AEP (50%)	187.4		10.38%	(b)
Transource Missouri	Missouri	2016	Evergy, Inc. (13.5%) (d) AEP (86.5%) (d)	310.5		11.2%	(c)
Transource West Virginia	West Virginia	2019	Evergy, Inc. (13.5%) (d) AEP (86.5%) (d)	82.0		10.5%	
Transource Maryland	Maryland	2022	Evergy, Inc. (13.5%) (d) AEP (86.5%) (d)	23.1	(e)	10.4%	
Transource Pennsylvania	Pennsylvania	2022	Evergy, Inc. (13.5%) (d) AEP (86.5%) (d)	238.9	(e)	10.4%	

(a) ETT is undertaking multiple projects and the completion dates will vary for those projects. ETT's investment in completed and active projects in ERCOT is expected to be $3.4 billion. Future projects will be evaluated on a case-by-case basis.

(b) In November 2019, Pioneer received FERC approval authorizing an ROE of 9.88% (10.38% inclusive of the RTO incentive adder of 0.5%.

(c) The ROE represents the weighted average approved ROE based on the costs of two projects developed by Transource Missouri; the $64 million Iatan-Nashua project (10.3%) and the $247 million Sibley-Nebraska City project (11.3%).

(d) AEP owns 86.5% of Transource Missouri, Transource West Virginia, Transource Maryland and Transource Pennsylvania through its ownership interest in Transource Energy, LLC (Transource). Transource is a joint venture with AEPTHCo and Evergy, Inc. formed to pursue competitive transmission projects. AEPTHCo and Evergy, Inc. own 86.5% and 13.5% of Transource, respectively.

(e) In August 2016, Transource Maryland and Transource Pennsylvania received approval from the PJM Interconnection Board to construct portions of a transmission project located in both Maryland and Pennsylvania. The project is expected to go in service in 2022. Project costs are in 2019 dollars.

Transource Missouri, Transource West Virginia, Transource Maryland and Transource Pennsylvania are consolidated joint ventures by AEP. All other joint ventures in the table above are not consolidated by AEP. AEP's joint ventures do not have employees. Business services for the joint ventures are provided by AEPSC and other AEP subsidiaries and the joint venture partners. During 2019, approximately 608 AEPSC employees and 291 operating company employees provided service to one or more joint ventures.

REGULATION

The State Transcos and the Transmission Joint Ventures located outside of ERCOT establish transmission rates annually through forward looking formula rate filings with the FERC pursuant to FERC-approved implementation protocols. The protocols include a transparent, formal review process to ensure the updated transmission rates are prudently incurred and reasonably calculated. The IMTCo-owned Greentown station assets acquired from Duke Energy Indiana, LLC in December 2018 are located in MISO. IMTCo utilizes a historic cost recovery model to recover MISO assets.

The State Transcos' and the Transmission Joint Ventures' (where applicable) rates are included in the respective OATT for PJM and SPP. An OATT is the FERC rate schedule that provides the terms and conditions for transmission and related services on a transmission provider's transmission system. The FERC requires transmission providers such as PJM and SPP to offer transmission service to all eligible customers (for example, load-serving entities, power marketers, generators and customers) on a non-discriminatory basis.

The FERC-approved formula rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners in annual rate base filings with the FERC. The formula rates establish rates for a one-year period based on the current projects in-service and proposed projects for a defined timeframe. The formula rates also include a true-up calculation for the previous year's billings, allowing for over/under-recovery of the transmission owner's ATRR. PJM and SPP pay the transmission owners their ATRR for use of their facilities and bill transmission customers taking service under the PJM and SPP OATTs, based on the terms and conditions in the respective OATT for the service taken. Additionally, the State Transcos are subject to reliability standards promulgated by the North American Electric Reliability Corporation, with the approval of the FERC.

The authorized returns on equity for the State Transcos are the FERC-authorized returns on equity in the PJM and SPP OATTs, respectively. These returns were challenged by parties in filings before the FERC. AEP's transmission owning subsidiaries within PJM entered into a settlement agreement, approved by the FERC in May 2019, that established a total ROE of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%) based on a capital structure of up to 55% equity for APTCo, IMTCo, KTCo, OHTCo and WVTCo (the East Transcos). In June 2019, the FERC approved an unopposed settlement agreement between AEP's transmission owning subsidiaries within SPP that established a total ROE of 10.0% (10.5% inclusive of the RTO incentive adder of 0.5%) without a cap on the capital structure for OKTCo and SWTCo (the West Transcos).

In the annual rate base filings described above, the State Transcos in aggregate filed rate base totals of \$5.9 billion, \$4.6 billion and \$3.8 billion for 2019, 2018 and 2017, respectively. The total filed transmission revenue requirements, including prior year over/under-recovery of revenue and associated carrying charges were \$992 million, \$829 million and \$690 million for 2019, 2018, and 2017, respectively.

The rates of ETT, which is located in ERCOT, are determined by the PUCT. ETT sets its rates through a combination of base rate cases and interim Transmission Cost of Services (TCOS) filings. ETT may file interim TCOS filings semi-annually to update its rates to reflect changes in its net invested capital.

The Transmission Joint Ventures have approved ROEs ranging from 9.6% to 12.8% based on equity capital structures ranging from 40% to 60%.

GENERATION & MARKETING

GENERAL

The AEP Generation & Marketing segment subsidiaries consist of competitive generating assets, a wholesale energy trading and marketing business and a retail supply and energy management business. The primary fossil generation subsidiary in the Generation & Marketing segment is AGR. As of December 31, 2019, AGR owns 1,294 MWs of generating capacity. Management plans to close 51% of this generation capacity in May 2020. Almost all of the remaining generating capacity is operated by Buckeye Power, a nonaffiliated electric cooperative. Other subsidiaries in this segment own or have the right to receive power from additional generation assets. See Item 2 – Properties for more information regarding the generation assets of the Generation & Marketing segment. AGR is a competitive generation subsidiary.

With respect to the wholesale energy trading and marketing business, AEP Generation & Marketing segment subsidiaries enter into short-term and long-term transactions to buy or sell capacity, energy and ancillary services in ERCOT, SPP, MISO and PJM. These subsidiaries sell power into the market and engage in power, natural gas and emissions allowances risk management and trading activities. These activities primarily involve the purchase-and-sale of electricity (and to a lesser extent, natural gas and emissions allowances) under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. The majority of forward contracts are typically settled by entering into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges.

With respect to the retail supply and energy management business, AEP Energy is a retail energy supplier that supplies electricity and/or natural gas to residential, commercial, and industrial customers. AEP Energy provides various energy solutions in Illinois, Pennsylvania, Delaware, Maryland, New Jersey, Ohio and Washington, D.C. AEP Energy also provides demand-side management solutions nationwide. AEP Energy had approximately 470,000 customer accounts as of December 31, 2019.

AEP Energy Supply, LLC is a holding company with several divisions, including AEP Renewables and AEP OnSite Partners.

AEP Renewables develops, owns and operates utility scale renewable projects backed with long-term contracts with creditworthy counterparties throughout the United States. AEP Renewables works directly with stakeholders to ensure that customers have clean, sustainable renewable energy to meet their environmental goals. As of December 31, 2019, AEP Renewables owned projects operating in 11 states, including approximately 1,212 MWs of installed wind capacity and approximately 90 MWs of installed solar capacity. These figures include the 2019 addition of 724 MWs of wind generation and battery assets located in several states acquired from Sempra Renewables LLC and the 75% interest, or 227 MWs, of Santa Rita East wind generation located in west Texas. In October 2019, AEP Renewables entered into an agreement to construct Flat Ridge 3, a wind farm in Kansas. The 128 MW facility is expected to reach commercial operation before the end of 2020.

AEP OnSite Partners works directly with wholesale and large retail customers to provide tailored solutions to reduce their energy costs based upon market knowledge, innovative applications of technology and deal structuring capabilities. AEP OnSite Partners targets opportunities in distributed solar, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other energy solutions that create value for customers. AEP OnSite Partners pursues and develops behind the meter projects with creditworthy customers. As of December 31, 2019, AEP OnSite Partners owned projects located in 17 states, including approximately 119 MWs of installed solar capacity, and approximately 28 MWs of solar projects under construction.

REGULATION

AGR is a public utility under the Federal Power Act, and is subject to the FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, the FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. The FERC granted AGR market-based rate authority in December 2013. The FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of AGR and set cost-based rates if the FERC subsequently determines that it can exercise market power, create barriers to entry or engage in abusive affiliate transactions. Periodically, AGR is required to file a market power update to show that it continues to meet the FERC's standards with respect to generation market power and other criteria used to evaluate whether it continues to qualify for market-based rates. Other matters subject to the FERC jurisdiction include, but are not limited to, review of mergers, and dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility.

Specific operations of AGR are also subject to the jurisdiction of various other federal, state, regional and local agencies, including federal and state environmental protection agencies. AGR is also regulated by the PUCT for transactions inside ERCOT. Additionally, AGR is subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation, with the approval of the FERC.

COMPETITION

The AEP Generation & Marketing segment subsidiaries face competition for the sale of available power, capacity and ancillary services. The principal factors of impact are electricity and fuel prices, new market entrants, construction or retirement of generating assets by others and technological advances in power generation. Because most of AGR's remaining generation is coal-fired, lower relative natural gas prices will favor competitors that have a higher concentration of natural gas fueled generation. Other factors impacting competitiveness include environmental regulation, transmission congestion or transportation constraints at or near generation facilities, inoperability or inefficiencies, outages and deactivations and retirements at generation facilities.

Technology advancements, increased demand for clean energy, changing consumer behaviors, low-priced and abundant natural gas, and regulatory and public policy reforms are among the catalysts for transformation within the industry that impact competition for AEP's Generation & Marketing segment. AGR also competes with self-generation and with distributors of other energy sources, such as natural gas, fuel oil, renewables and coal, within their service areas. The primary factors in such competition are price, unit availability and the capability of customers to utilize sources of energy other than electric power.

Changes in regulatory policies and advances in newer technologies for batteries or energy storage, fuel cells, microturbines, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production. The ability to maintain relatively low cost, efficient and reliable operations and to provide cost-effective programs and services to customers are significant determinants of AGR's competitiveness. The costs of photovoltaic solar cells in particular have continued to become increasingly competitive.

This segment's retail operations provide competitive electricity and natural gas in deregulated retail energy markets in six states and Washington, D.C. Each such retail choice jurisdiction establishes its own laws and regulations governing its competitive market, and public utility commission communications and utility default service pricing can affect customer participation in retail competition. Sustained low natural gas and power prices, low market volatility and maturing competitive environments can adversely affect this business.

This segment also engages in procuring and selling output from renewable generation sources under long-term contracts to creditworthy counterparties. New sources are not acquired without first securing a long-term placement of such power. Existing sources do not face competitive exposure. Competitive nonaffiliated suppliers of renewable or other generation could limit opportunities for future transactions for new sources and related output contracts.

SEASONALITY

The consumption of electric power is generally seasonal. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter months. The pattern of this fluctuation may change.

Fuel Supply

The following table shows the generation sources by type, on an actual net generation (MWhs) basis, used by the Generation & Marketing segment, not including AEP Energy Partners' offtake agreement from the Oklaunion Power Station:

	2019	2018	2017
Coal	64%	88%	85%
Natural Gas	—%	—%	8%
Renewables	36%	12%	7%

Management expects the decline in coal generation sources to continue into 2020 due to the shutdown of Conesville Unit 4 in May 2020.

Coal and Consumables

AGR procures coal and consumables needed to burn the coal under a combination of purchasing arrangements including long-term and spot contracts with various producers and coal trading firms. As contracts expire, they are replaced, as needed, with contracts at market prices. Coal and consumable inventories remain adequate to meet generation requirements.

Management believes that AGR will be able to secure and transport coal and consumables of adequate quality and in adequate quantities to operate their coal-fired units. AGR, through its contracts with third party transporters, has the ability to adequately move and store coal and consumables for use in its generating facilities. AGR plants consumed 2.5 million tons of coal in 2019.

The coal supplies at AGR plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, coal quality, availability of acceptable coals, labor issues and weather conditions, which may interrupt production or deliveries. AGR aims to maintain the coal inventory of its managed plants in the range of 20 to 60 days of full load burn. As of December 31, 2019, the coal inventory of AGR was within the target range.

Counterparty Risk Management

Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2019, counterparties posted approximately $16 million in cash, cash equivalents or letters of credit with AEP for the benefit of AEP's Generation & Marketing segment subsidiaries (while, as of that date, AEP's Generation & Marketing segment subsidiaries posted approximately $169 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See the "Quantitative and Qualitative Disclosures About Market Risk" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

Certain Power Agreements

As of December 31, 2019, the assets utilized in this segment included approximately 1,212 MWs of company-owned domestic wind power facilities, 101 MWs of domestic wind power from long-term purchase power agreements and 355 MWs of coal-fired capacity which was obtained through an agreement effective through 2027 that transfers the interest of AEP Texas in the Oklaunion Power Station to AEPEP. Management has announced plans to close Oklaunion Power Station by October 2020. The power obtained from the Oklaunion Power Station is marketed and sold in ERCOT.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following persons are executive officers of AEP. Their ages are given as of February 20, 2020. The officers are appointed annually for a one-year term by the board of directors of AEP.

Nicholas K. Akins
Chairman of the Board, President and Chief Executive Officer
Age 59
Chairman of the Board since January 2014, President since January 2011 and Chief Executive Officer since November 2011.

Lisa M. Barton
Executive Vice President - Utilities
Age 54
Executive Vice President - Transmission from August 2011 to December 2018.

Paul Chodak, III
Executive Vice President - Generation
Age 56
Executive Vice President - Utilities from January 2017 to December 2018. President and Chief Operating Officer of I&M from July 2010 to December 2016.

David M. Feinberg
Executive Vice President, General Counsel and Secretary
Age 50
Executive Vice President since January 2013.

Lana L. Hillebrand
Executive Vice President and Chief Administrative Officer
Age 59
Chief Administrative Officer since December 2012 and Senior Vice President from December 2012 to December 2016.

Mark C. McCullough
Executive Vice President - Transmission
Age 60
Executive Vice President - Generation from January 2011 to December 2018.

Charles R. Patton
Executive Vice President - External Affairs
Age 60
Executive Vice President - External Affairs since January 2017. President and Chief Operating Officer of APCo from June 2010 to December 2016.

Brian X. Tierney
Executive Vice President and Chief Financial Officer
Age 52
Executive Vice President and Chief Financial Officer since October 2009.

Charles E. Zebula
Executive Vice President - Energy Supply
Age 59
Executive Vice President - Energy Supply since January 2013.

ITEM 1A. RISK FACTORS

GENERAL RISKS OF REGULATED OPERATIONS

AEP may not be able to recover the costs of substantial planned investment in capital improvements and additions. (Applies to all Registrants)

AEP's business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction of additional transmission facilities, modernizing existing infrastructure as well as other initiatives. AEP's public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates charged, affected AEP subsidiaries would not be able to recover the costs associated with their investments. This would cause financial results to be diminished.

Regulated electric revenues and earnings are dependent on federal and state regulation that may limit AEP's ability to recover costs and other amounts. (Applies to all Registrants)

The rates customers pay to AEP regulated utility businesses are subject to approval by the FERC and the respective state utility commissions of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. In certain instances, AEP's applicable regulated utility businesses may agree to negotiated settlements related to various rate matters that are subject to regulatory approval. AEP cannot predict the ultimate outcomes of any settlements or the actions by the FERC or the respective state commissions in establishing rates.

If regulated utility earnings exceed the returns established by the relevant commissions, retail electric rates may be subject to review and possible reduction by the commissions, which may decrease future earnings. Additionally, if regulatory bodies do not allow recovery of costs incurred in providing service on a timely basis, it could reduce future net income and cash flows and negatively impact financial condition. Similarly, if recovery or other rate relief authorized in the past is overturned or reversed on appeal, future earnings could be negatively impacted. Any regulatory action or litigation outcome that triggers a reversal of a regulatory asset or deferred cost generally results in an impairment to the balance sheet and a charge to the income statement of the company involved. See Note 4 – Rate Matters included in the 2019 Annual Report for additional information.

AEP's transmission investment strategy and execution are dependent on federal and state regulatory policy. (Applies to all Registrants)

A significant portion of AEP's earnings is derived from transmission investments and activities. FERC policy currently favors the expansion and updating of the transmission infrastructure within its jurisdiction. If the FERC were to adopt a different policy, if states were to limit or restrict such policies, or if transmission needs do not continue or develop as projected, AEP's strategy of investing in transmission could be impacted. Management believes AEP's experience with transmission facilities construction and operation gives AEP an advantage over other competitors in securing authorization to install, construct and operate new transmission lines and facilities. However, there can be no assurance that PJM, SPP, ERCOT or other RTOs will authorize new transmission projects or will award such projects to AEP.

Certain elements of AEP's transmission formula rates have been challenged, which could result in lowered rates and/or refunds of amounts previously collected and thus have an adverse effect on AEP's business, financial condition, results of operations and cash flows. (Applies to all Registrants other than AEP Texas)

AEP provides transmission service under rates regulated by the FERC. The FERC has approved the cost-based formula rate templates used by AEP to calculate its respective annual revenue requirements, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of AEP's rates accepted or approved by the FERC, including the formula rate templates, the rates of return on the actual equity portion of its respective capital structures and the approved targeted capital structures, are subject to challenge by interested parties at the FERC, or by the FERC on its own initiative. In addition, interested parties may challenge the annual implementation and calculation by AEP of its projected rates and formula rate true up pursuant to its approved formula rate templates under AEP's formula rate implementation protocols. If a challenger can establish that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then the FERC can make appropriate prospective adjustments to them and/or disallow any of AEP's inclusion of those aspects in the rate setting formula.

AEP settled challenges to its SPP and PJM formula rates in proceedings at the FERC in 2019. However, inquiries related to rates of return, as well as challenges to the formula rates of other utilities, are ongoing in other proceedings at the FERC. The results of these proceedings could potentially negatively impact AEP in any future challenges to AEP's formula rates. If the FERC orders revenue reductions, including refunds, in any future cases related to its formula rates, it could reduce future net income and cash flows and impact financial condition.

End-use consumers and entities supplying electricity to end-use consumers may also attempt to influence government and/or regulators to change the rate setting methodologies that apply to AEP, particularly if rates for delivered electricity increase substantially.

Changes in technology and regulatory policies may lower the value of electric utility facilities and franchises. (Applies to all Registrants)

AEP primarily generates electricity at large central facilities and delivers that electricity to customers over its transmission and distribution facilities to customers usually situated within an exclusive franchise. This method results in economies of scale and generally lower costs than newer technologies such as fuel cells and microturbines, and distributed generation using either new or existing technology. Other technologies, such as light emitting diodes (LEDs), increase the efficiency of electricity and, as a result, lower the demand for it. Changes in regulatory policies and advances in batteries or energy storage, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production and delivery. These developments can challenge AEP's competitive ability to maintain relatively low cost, efficient and reliable operations, to establish fair regulatory mechanisms and to provide cost-effective programs and services to customers. Further, in the event that alternative generation resources are mandated, subsidized or encouraged through legislation or regulation or otherwise are economically competitive and added to the available generation supply, such resources could displace a higher marginal cost generating units, which could reduce the price at which market participants sell their electricity.

AEP may not recover costs incurred to begin construction on projects that are canceled. (Applies to all Registrants)

AEP's business plan for the construction of new projects involves a number of risks, including construction delays, nonperformance by equipment and other third-party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, AEP's subsidiaries enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects are canceled for any reason, including failure to receive necessary regulatory approvals and/or siting or environmental permits, significant cancellation penalties under the equipment purchase orders and construction contracts could occur. In addition, if any construction work or investments have been recorded as an asset, an impairment may need to be recorded in the event the project is canceled.

AEP is exposed to nuclear generation risk. (Applies to AEP and I&M)

I&M owns the Cook Plant, which consists of two nuclear generating units for a rated capacity of 2,288 MWs, or about 7% of the generating capacity in the AEP System. AEP and I&M are, therefore, subject to the risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health due to an adverse incident/event resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as SNF.

- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations.
- Uncertainties with respect to contingencies and assessment amounts triggered by a loss event (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the coverage for losses of others).
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if these risks are triggered.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants. In addition, although management has no reason to anticipate a serious nuclear incident at the Cook Plant, if an incident did occur, it could harm results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the U.S. could require AEP or I&M to make material contributory payments.

Costs associated with the operation (including fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. Costs also may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs. The ability to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured.

AEP subsidiaries are exposed to risks through participation in the market and transmission structures in various regional power markets that are beyond their control. (Applies to all Registrants)

Results are likely to be affected by differences in the market and transmission structures in various regional power markets. The rules governing the various RTOs, including SPP and PJM, may also change from time to time which could affect costs or revenues. Existing, new or changed rules of these RTOs could result in significant additional fees and increased costs to participate in those structures, including the cost of transmission facilities built by others due to changes in transmission rate design. In addition, these RTOs may assess costs resulting from improved transmission reliability, reduced transmission congestion and firm transmission rights. As members of these RTOs, AEP's subsidiaries are subject to certain additional risks, including the allocation among existing members, of losses caused by unreimbursed defaults of other participants in these markets and resolution of complaint cases that may seek refunds of revenues previously earned by members of these markets.

AEP could be subject to higher costs and/or penalties related to mandatory reliability standards. (Applies to all Registrants)

Owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by the FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with new reliability standards may subject AEP to higher operating costs and/or increased capital expenditures. While management expects to recover costs and expenditures from customers through regulated rates, there can be no assurance that the applicable commissions will approve full recovery in a timely manner. If AEP were found not to be in compliance with the mandatory reliability standards, AEP could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

A substantial portion of the receivables of AEP Texas is concentrated in a small number of REPs, and any delay or default in payment could adversely affect its cash flows, financial condition and results of operations. (Applies to AEP and AEP Texas)

AEP Texas collects receivables from the distribution of electricity from REPs that supply the electricity it distributes to its customers. As of December 31, 2019, AEP Texas did business with approximately 120 REPs. Adverse economic conditions, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these REPs to pay for these services or could cause them to delay such payments. AEP Texas depends on these REPs to remit payments on a timely basis. Applicable regulatory provisions require that customers be shifted to another REP or a provider of last resort if a REP cannot make timely payments. Applicable PUCT regulations significantly limit the extent to which AEP Texas can apply normal commercial terms or otherwise seek credit protection from firms desiring to provide retail electric service in its service territory, and AEP Texas thus remains at risk for payments related to services provided prior to the shift to another REP or the provider of last resort. In 2019, AEP Texas' first, second and third largest REPs accounted for 20%, 14% and 14%, respectively, of its operating revenue. Any delay or default in payment by REPs could adversely affect cash flows, financial condition and results of operations. If a REP were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations, and claims might be made by creditors involving payments AEP Texas had received from such REP.

RISKS RELATED TO MARKET, ECONOMIC OR FINANCIAL VOLATILITY AND OTHER RISKS

AEP's financial performance may be adversely affected if AEP is unable to successfully operate facilities or perform certain corporate functions. (Applies to all Registrants)

Performance is highly dependent on the successful operation of generation, transmission and/or distribution facilities. Operating these facilities involves many risks, including:

- Operator error and breakdown or failure of equipment or processes.
- Operating limitations that may be imposed by environmental or other regulatory requirements.
- Labor disputes.
- Compliance with mandatory reliability standards, including mandatory cyber security standards.
- Information technology failure that impairs AEP's information technology infrastructure or disrupts normal business operations.
- Information technology failure that affects AEP's ability to access customer information or causes loss of confidential or proprietary data that materially and adversely affects AEP's reputation or exposes AEP to legal claims.
- Fuel or water supply interruptions caused by transportation constraints, adverse weather such as drought, non-performance by suppliers and other factors.
- Catastrophic events such as fires, earthquakes, explosions, hurricanes, tornados, ice storms, terrorism (including cyber-terrorism), floods or other similar occurrences.
- Fuel costs and related requirements triggered by financial stress in the coal industry.

Physical attacks or hostile cyber intrusions could severely impair operations, lead to the disclosure of confidential information and damage AEP's reputation. (Applies to all Registrants)

AEP and its regulated utility businesses face physical security and cybersecurity risks as the owner-operators of generation, transmission and/or distribution facilities and as participants in commodities trading. AEP and its regulated utility businesses own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run these facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. bulk power system or AEP operations could view these computer systems, software or networks as targets for cyber attack. In addition, the electric utility business requires the collection of sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A security breach of AEP or its regulated utility businesses' physical assets or information systems, interconnected entities in RTOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject AEP and its regulated utility businesses to financial harm associated with theft or inappropriate release of certain types of information, including sensitive customer, vendor, employee, trading or other confidential data. A successful cyber attack on the systems that control generation, transmission, distribution or other assets could severely disrupt business operations, preventing service to customers or collection of revenues. The breach of certain business systems could affect the ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to AEP's reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. For these reasons, a significant cyber incident could reduce future net income and cash flows and negatively impact financial condition.

If AEP is unable to access capital markets on reasonable terms, it could reduce future net income and cash flows and negatively impact financial condition. (Applies to all Registrants)

AEP relies on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Volatility, increased interest rates and reduced liquidity in the financial markets could affect AEP's ability to raise capital on reasonable terms to fund capital needs, including construction costs and refinancing maturing indebtedness. Certain sources of debt and equity capital expressed increasing unwillingness to invest in companies, such as AEP, that rely on fossil fuels. If sources of capital for AEP are reduced, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could reduce future net income and cash flows and negatively impact financial condition.

Shareholder activism could cause AEP to incur significant expense, hinder execution of AEP's business strategy and impact AEP's stock price. (Applies to all Registrants)

Shareholder activism, which can take many forms and arise in a variety of situations, could result in substantial costs and divert management's and AEP's board's attention and resources from AEP's business. Additionally, such shareholder activism could give rise to perceived uncertainties as to AEP's future, adversely affect AEP's relationships with its employees, customers or service providers and make it more difficult to attract and retain qualified personnel. Also, AEP may be required to incur significant fees and other expenses related to activist shareholder matters, including for third-party advisors. AEP's stock price could be subject to significant fluctuation or otherwise be adversely affected by the events, risks and uncertainties of any shareholder activism.

The potential phasing out of LIBOR after 2021 may adversely affect the costs and availability of financing. (Applies to all Registrants)

A portion of the Registrants' indebtedness bears interest at fluctuating interest rates, primarily based on the London interbank offered rate ("LIBOR") for deposits of U.S. dollars. LIBOR tends to fluctuate based on general interest rates, rates set by the U.S. Federal Reserve and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. Accordingly, Registrants' interest expense for any particular period will fluctuate based on LIBOR and other variable interest rates. On July 27, 2017, the Financial Conduct Authority (the authority that regulates LIBOR) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, is considering replacing U.S. dollar LIBOR with the Secured Overnight Funding Rate, which is calculated based on repurchase agreements backed by treasury securities. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United Kingdom, the United States or elsewhere. To the extent these interest rates increase, interest expense will increase. If sources of capital for the Registrants are reduced, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could reduce future net income and cash flows and negatively impact financial condition and/or liquidity.

Downgrades in AEP's credit ratings could negatively affect its ability to access capital. (Applies to all Registrants)

The credit ratings agencies periodically review AEP's capital structure and the quality and stability of earnings and cash flows. Any negative ratings actions could constrain the capital available to AEP and could limit access to funding for operations. Recently a credit rating agency placed AEP's credit rating on negative outlook primarily because a key criterion, the ratio of cash flow from operations (excluding working capital) to debt, is expected to decline due to higher capital spending and lower cash flows resulting from changes in tax law. AEP's business is capital intensive, and AEP is dependent upon the ability to access capital at rates and on terms management determines to be attractive. If AEP's ability to access capital becomes significantly constrained, AEP's interest costs will likely increase and could reduce future net income and cash flows and negatively impact financial condition.

AEP and AEPTCo have no income or cash flow apart from dividends paid or other payments due from their subsidiaries. (Applies to AEP and AEPTCo)

AEP and AEPTCo are holding companies and have no operations of their own. Their ability to meet their financial obligations associated with their indebtedness and to pay dividends is primarily dependent on the earnings and cash flows of their operating subsidiaries, primarily their regulated utilities, and the ability of their subsidiaries to pay dividends to, or repay loans from them. Their subsidiaries are separate and distinct legal entities that have no obligation (apart from loans from AEP or AEPTCo) to provide them with funds for their payment obligations, whether by dividends, distributions or other payments. Payments to AEP or AEPTCo by their subsidiaries are also contingent upon their earnings and business considerations. AEP and AEPTCo indebtedness and dividends are structurally subordinated to all subsidiary indebtedness.

AEP's operating results may fluctuate on a seasonal or quarterly basis and with general economic and weather conditions. (Applies to all Registrants)

Electric power consumption is generally seasonal. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, overall operating results in the future may fluctuate substantially on a seasonal basis. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could reduce future net income and cash flows and negatively impact financial condition. In addition, unusually extreme weather conditions could impact AEP's results of operations in a manner that would not likely be sustainable.

Further, deteriorating economic conditions triggered by any cause, including international tariffs, generally result in reduced consumption by customers, particularly industrial customers who may curtail operations or cease production entirely, while an expanding economic environment generally results in increased revenues. As a result, prevailing economic conditions may reduce future net income and cash flows and negatively impact financial condition.

Volatility in the securities markets, interest rates, and other factors could substantially increase defined benefit pension and other postretirement plan costs and the costs of nuclear decommissioning. (Applies to all Registrants and to AEP and I&M with respect to the costs of nuclear decommissioning)

The costs of providing pension and other postretirement benefit plans are dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, changes in actuarial assumptions, future government regulation, changes in life expectancy, and the frequency and amount of AEP's required or voluntary contributions made to the plans. Changes in actuarial assumptions and differences between the assumptions and actual values, as well as a significant decline in the value of investments that fund the pension and other postretirement plans, if not offset or mitigated by a decline in plan liabilities, could increase pension and other postretirement expense, and AEP could be required from time to time to fund the pension plan with significant amounts of cash. Such cash funding obligations could have a material impact on liquidity by reducing cash flows and could negatively affect results of operations.

Additionally, I&M holds a significant amount of assets in its nuclear decommissioning trusts to satisfy obligations to decommission its nuclear plant. The rate of return on assets held in those trusts can significantly impact both the costs of decommissioning and the funding requirements for the trusts.

AEP's results of operations and cash flows may be negatively affected by a lack of growth or slower growth in the number of customers, or decline in customer demand. (Applies to all Registrants)

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and the need for additional power generation and delivery facilities. Customer growth and customer usage are affected by a number of factors outside the control of AEP, such as mandated energy efficiency measures, demand-side management goals, distributed generation resources and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity.

Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to further reduce energy consumption. Additionally, technological advances or other improvements in or applications of technology could lead to declines in per capita energy consumption. Some or all of these factors, could impact the demand for electricity.

Failure to attract and retain an appropriately qualified workforce could harm results of operations. (Applies to all Registrants)

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate the business. If AEP is unable to successfully attract and retain an appropriately qualified workforce, future net income and cash flows may be reduced.

Changes in the price of commodities, the cost of procuring fuel, emission allowances for criteria pollutants and the costs of transport may increase AEP's cost of producing power, impacting financial performance. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

AEP is exposed to changes in the price and availability of fuel (including the cost to procure coal and gas) and the price and availability to transport fuel. AEP has existing contracts of varying durations for the supply of fuel, but as these contracts end or if they are not honored, AEP may not be able to purchase fuel on terms as favorable as the current contracts. The inability to procure fuel at costs that are economical could cause AEP to retire generating capacity prior to the end of its useful life, and while AEP typically recovers expenditures for undepreciated plant balances, there can be no assurance in the future that AEP will recover such costs. Similarly, AEP is exposed to changes in the price and availability of emission allowances. AEP uses emission allowances based on the amount of fuel used and reductions achieved through emission controls and other measures. Based on current environmental programs remaining in effect, AEP has sufficient emission allowances to cover the majority of the projected needs for the next two years and beyond. If the Federal EPA attempts to further reduce interstate transport, and it is acceptable by the courts, additional costs may be incurred either to acquire additional allowances or to achieve further reductions in emissions. If AEP needs to obtain allowances, those purchases may not be on as favorable terms as those under the current environmental programs. AEP's risks relative to the price and availability to transport coal include the volatility of the price of diesel which is the primary fuel used in transporting coal by barge.

Prices for coal, natural gas and emission allowances have shown material swings in the past. Changes in the cost of fuel, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power could reduce future net income and cash flows and negatively impact financial condition.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value trading and marketing transactions, and those differences may be material. As a result, as those transactions are marked-to-market, they may impact future results of operations and cash flows and impact financial condition.

AEP is subject to physical and financial risks associated with climate change. (Applies to all Registrants)

Climate change creates physical and financial risk. Physical risks from climate change may include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events, such as fires. Customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

Increased energy use due to weather changes may require AEP to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect financial condition through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of the AEP service territory could also have an impact on revenues. AEP buys and sells electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on AEP's own and/or other systems may raise electricity prices as AEP buys short-term energy to serve AEP's own system, which would increase the cost of energy AEP provides to customers.

Severe weather and weather-related events impact AEP's service territories, primarily when thunderstorms, tornadoes, hurricanes, fires, floods and snow or ice storms occur. To the extent the frequency and intensity of extreme weather events and storms increase, AEP's cost of providing service will increase, and these costs may not be recoverable. Changes in precipitation resulting in droughts, water shortages or floods could adversely affect operations, principally the fossil fuel generating units. A negative impact to water supplies due to long-term drought conditions or severe flooding could adversely impact AEP's ability to provide electricity to customers, as well as increase the price they pay for energy. AEP may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact revenues. AEP's financial performance is tied to the health of the regional economies AEP serves. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of the communities within the AEP System.

Management cannot predict the outcome of the legal proceedings relating to AEP's business activities. (Applies to all Registrants)

AEP is involved in legal proceedings, claims and litigation arising out of its business operations, the most significant of which are summarized in Note 6 - Commitments, Guarantees and Contingencies included in the 2019 Annual Report. Adverse outcomes in these proceedings could require significant expenditures that could reduce future net income and cash flows and negatively impact financial condition.

Disruptions at power generation facilities owned by third-parties could interrupt the sales of transmission and distribution services. (Applies to AEP and AEP Texas)

AEP Texas transmits and distributes electric power that the REPs obtain from power generation facilities owned by third-parties. If power generation is disrupted or if power generation capacity is inadequate, sales of transmission and distribution services may be diminished or interrupted, and results of operations, financial condition and cash flows could be adversely affected.

Hazards associated with high-voltage electricity transmission may result in suspension of AEP's operations or the imposition of civil or criminal penalties. (Applies to all Registrants)

AEP operations are subject to the usual hazards associated with high-voltage electricity transmission, including explosions, fires, inclement weather, natural disasters, mechanical failure, unscheduled downtime, equipment interruptions, remediation, chemical spills, discharges or releases of toxic or hazardous substances or gases and other environmental risks. The hazards can cause personal injury and loss of life, severe damage to or destruction of property and equipment and environmental damage, and may result in suspension of operations and the imposition of civil or criminal penalties. AEP maintains property and casualty insurance, but AEP is not fully insured against all potential hazards incident to AEP's business, such as damage to poles, towers and lines or losses caused by outages.

AEPTCo depends on its affiliates in the AEP System for a substantial portion of its revenues. (Applies to AEPTCo)

AEPTCo's principal transmission service customers are its affiliates in the AEP System. Management expects that these affiliates will continue to be AEPTCo's principal transmission service customers for the foreseeable future. For the year ended December 31, 2019, its affiliates were responsible for approximately 79% of the consolidated transmission revenues of AEPTCo.

Most of the real property rights on which the assets of AEPTCo are situated result from affiliate license agreements and are dependent on the terms of the underlying easements and other rights of its affiliates. (Applies to AEPTCo)

AEPTCo does not hold title to the majority of real property on which its electric transmission assets are located. Instead, under the provisions of certain affiliate contracts, it is permitted to occupy and maintain its facilities upon real property held by the respective AEP System utility affiliate that overlay its operations. The ability of AEPTCo to continue to occupy such real property is dependent upon the terms of such affiliate contracts and upon the underlying real property rights of these utility affiliates, which may be encumbered by easements, mineral rights and other similar encumbrances that may affect the use of such real property. AEP can give no assurance that (a) the relevant AEP System utility affiliates will continue to be affiliates of AEPTCo, (b) suitable replacement arrangements can be obtained in the event that the relevant AEP System utility affiliates are not its affiliates and (c) the underlying easements and other rights are sufficient to permit AEPTCo to operate its assets in a manner free from interruption.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

Costs of compliance with existing environmental laws are significant. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

Operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. A majority of the electricity generated by the AEP System is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates and the discharge and disposal of solid waste (including coal-combustion residuals or "CCR") resulting from fossil fueled generation plants are subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires AEP to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees, disposal and permits at AEP facilities and could cause AEP to retire generating capacity prior to the end of its estimated useful life. Costs of compliance with environmental statutes and regulations could reduce future net income and negatively impact financial condition, especially if emission, CCR waste and/or discharge obligations are tightened, more extensive operating and/or permitting requirements are imposed or additional substances become regulated. Although AEP typically recovers expenditures for pollution control technologies, replacement generation, undepreciated plant balances and associated operating costs from customers, there can be no assurance in the future that AEP will recover the remaining costs associated with such plants. Failure to recover these costs could reduce future net income and cash flows and possibly harm financial condition.

Regulation of CO_2 emissions could materially increase costs to AEP and its customers or cause some electric generating units to be uneconomical to operate or maintain. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

In 2014, the Federal EPA issued standards for new, modified and reconstructed units, and a guideline for the development of SIPs that would reduce carbon emissions from existing utility units. The standards and guidelines were finalized in 2015, and were challenged by several dozen states as well as industry groups and other stakeholders. The U.S. Supreme Court stayed the implementation of the guidelines for existing sources, known as the Clean Power Plan, while the courts considered those challenges. In 2017, the Federal EPA issued a proposal to repeal the Clean Power Plan, and in 2018, the Federal EPA proposed new guidelines that would allow states to establish unit-specific performance standards based on their evaluation of past performance and whether certain efficiency improvement measures could be applied at existing coal-fired units. The Federal EPA also proposed to change the new source performance standard for new coal-fired utility units to 1,900 - 2,000 pounds per MWh depending on the size of the unit, an increase from the current standard of 1,400 pounds per MWh, based on its determination that carbon capture and storage is not available everywhere and is not sufficiently cost-effective to be considered the best available control technology for coal-fired units. The new guidelines were finalized in 2019, and the Clean Power Plan was repealed. Challenges to both of these actions are pending in the U.S. Court of Appeals for the District of Columbia Circuit.

CO_2 standards could require significant increases in capital expenditures and operating costs and could impact the dates for retirement of AEP's coal-fired units. While AEP typically recovers costs of complying with new requirements, such as the potential CO_2 and other greenhouse gases emission standards from customers, there can be no assurance that AEP would recover such costs.

Courts adjudicating nuisance and other similar claims in the future may order AEP to pay damages or to limit or reduce emissions. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

In the past, there have been several cases seeking damages based on allegations of federal and state common law nuisance in which AEP, among others, were defendants. In general, the actions allege that emissions from the defendants' power plants constitute a public nuisance. The plaintiffs in these actions generally seek recovery of damages and other relief. If future actions are resolved against AEP, substantial modifications or retirement of AEP's existing coal-fired power plants could be required, and AEP might be required to purchase power from third-parties to fulfill AEP's commitments to supply power to AEP customers. This could have a material impact on revenues. In addition, AEP could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay damages or penalties and/or halt operations. Unless recovered, those costs could reduce future net income and cash flows and harm financial condition. Moreover, results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Commodity trading and marketing activities are subject to inherent risks which can be reduced and controlled but not eliminated. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

AEP routinely has open trading positions in the market, within guidelines set by AEP, resulting from the management of AEP's trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish financial results and financial position.

AEP's power trading activities also expose AEP to risks of commodity price movements. To the extent that AEP's power trading does not hedge the price risk associated with the generation it owns, or controls, AEP would be exposed to the risk of rising and falling spot market prices.

In connection with these trading activities, AEP routinely enters into financial contracts, including futures and options, OTC options, financially-settled swaps and other derivative contracts. These activities expose AEP to risks from price movements. If the values of the financial contracts change in a manner AEP does not anticipate, it could harm financial position or reduce the financial contribution of trading operations.

Parties with whom AEP has contracts may fail to perform their obligations, which could harm AEP's results of operations. (Applies to all Registrants)

AEP sells power from its generation facilities into the spot market and other competitive power markets on a contractual basis. AEP also enters into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of its power marketing and energy trading operations. AEP is exposed to the risk that counterparties that owe AEP money or the delivery of a commodity, including power, could breach their obligations. Should the counterparties to these arrangements fail to perform, AEP may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed AEP's contractual prices, which would cause financial results to be diminished and AEP might incur losses. Although estimates take into account the expected probability of default by a counterparty, actual exposure to a default by a counterparty may be greater than the estimates predict.

AEP relies on electric transmission facilities that AEP does not own or control. If these facilities do not provide AEP with adequate transmission capacity, AEP may not be able to deliver wholesale electric power to the purchasers of AEP's power. (Applies to all Registrants)

AEP depends on transmission facilities owned and operated by other nonaffiliated power companies to deliver the power AEP sells at wholesale. This dependence exposes AEP to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, AEP may not be able to sell and deliver AEP wholesale power. If a region's power transmission infrastructure is inadequate, AEP's recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions, access to transmission systems may not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. Management also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

OVEC may require additional liquidity and other capital support. (Applies to AEP, APCo, I&M and OPCo)

AEP and several nonaffiliated utility companies own OVEC. The Inter-Company Power Agreement (ICPA) defines the rights and obligations and sets the power participation ratio of the parties to it. Under the ICPA, parties are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,400 MWs) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. If a party fails to make payments owed by it under the ICPA, OVEC may not have sufficient funds to honor its payment obligations, including its ongoing operating expenses as well as its indebtedness. As of December 31, 2019, OVEC has outstanding indebtedness of approximately $1.4 billion, of which APCo, I&M, and OPCo are collectively responsible for $589 million through the ICPA. Although they are not an obligor or guarantor, APCo, I&M, and OPCo are responsible for their respective ratio of OVEC's outstanding debt through the ICPA.

FirstEnergy Solutions ("FES"), a nonaffiliated party, whose aggregate power participation ratio is 4.85% under the ICPA, has filed a petition seeking protection under bankruptcy law. Litigation related to these filings continues. In addition, as a result of these and prior related developments, OVEC's credit ratings have been adversely impacted.

If OVEC does not have sufficient funds to honor its payment obligations, there is risk that APCo, I&M and/or OPCo may need to make payments in addition to their power participation ratio payments. Further, if OVEC's indebtedness is accelerated for any reason, there is risk that APCo, I&M and/or OPCo may be required to pay some or all of such accelerated indebtedness in amounts equal to their aggregate power participation ratio of 43.47%. Also, as a result of the credit rating agencies' actions, OVEC's ability to access capital markets on terms as favorable as previously may diminish and its financing costs will increase.

ITEM 1B.   UNRESOLVED STAFF COMMENTS

None.

ITEM 2.   PROPERTIES

GENERATION FACILITIES

As of December 31, 2019, the AEP System owned (or leased where indicated) generation plants, with locations and net maximum power capabilities (winter rating), are shown in the following tables:

Vertically Integrated Utilities Segment

AEGCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Rockport, Units 1 and 2 – 50% of each (a)	2	IN	Steam - Coal	1,310	1984

(a) Rockport Plant, Unit 2 is leased.

APCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Buck	3	VA	Hydro	11	1912
Byllesby	4	VA	Hydro	19	1912
Claytor	4	VA	Hydro	75	1939
Leesville	2	VA	Hydro	50	1964
London	3	WV	Hydro	14	1935
Marmet	3	WV	Hydro	14	1935
Niagara	2	VA	Hydro	2	1906
Winfield	3	WV	Hydro	15	1938
Ceredo	6	WV	Natural Gas	516	2001
Dresden	3	OH	Natural Gas	613	2012
Smith Mountain	5	VA	Pumped Storage	585	1965
Amos	3	WV	Steam - Coal	2,930	1971
Mountaineer	1	WV	Steam - Coal	1,320	1980
Clinch River	2	VA	Steam - Natural Gas	465	1958
Total MWs				6,629	

I&M

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Berrien Springs	12	MI	Hydro	6	1908
Buchanan	10	MI	Hydro	3	1919
Constantine	4	MI	Hydro	1	1921
Elkhart	3	IN	Hydro	3	1913
Mottville	4	MI	Hydro	2	1923
Twin Branch Hydro	8	IN	Hydro	5	1904
Deer Creek Solar Farm	NA	IN	Solar	3	2016
Olive Solar Farm	NA	IN	Solar	5	2016
Twin Branch Solar Farm	NA	IN	Solar	3	2016
Watervliet	NA	MI	Solar	5	2016
Rockport (Units 1 and 2, 50% of each) (a)	2	IN	Steam - Coal	1,310	1984
Cook	2	MI	Steam - Nuclear	2,288	1975
Total MWs				3,634	

NA Not applicable.
(a) Rockport Plant, Unit 2 is leased.

The following table provides operating information related to the Cook Plant:

	Cook Plant	
	Unit 1	Unit 2
Year Placed in Operation	1975	1978
Year of Expiration of NRC License	2034	2037
Nominal Net Electrical Rating in MWs	1,084	1,204
Annual Capacity Utilization		
2019	77.3%	84.3%
2018	97.9%	79.5%
2017	76.5%	98.8%

KPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mitchell (a)	2	WV	Steam - Coal	780	1971
Big Sandy	1	KY	Steam - Natural Gas	280	1963
Total MWs				1,060	

(a) KPCo owns a 50% interest in the Mitchell Plant units. WPCo owns the remaining 50%. Figures presented reflect only the portion owned by KPCo.

PSO

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Comanche	3	OK	Natural Gas	248	1973
Riverside, Units 3 and 4	2	OK	Natural Gas	160	2008
Southwestern, Units 4 and 5	2	OK	Natural Gas	170	2008
Weleetka (a)	2	OK	Natural Gas	100	1975
Northeastern, Unit 1	1	OK	Natural Gas	470	1961
Northeastern, Unit 3	1	OK	Steam - Coal	469	1979
Oklaunion Power Station (b) (c)	1	TX	Steam - Coal	105	1986
Northeastern, Unit 2	1	OK	Steam - Natural Gas	434	1961
Riverside, Units 1 and 2	2	OK	Steam - Natural Gas	901	1974
Southwestern, Units 1, 2 and 3	3	OK	Steam - Natural Gas	451	1952
Tulsa	2	OK	Steam - Natural Gas	325	1956
Total MWs				3,833	

(a) Weleetka Unit 6 was retired in March 2019.
(b) Jointly-owned with AEP Texas and nonaffiliated entities. Figures presented reflect only the portion owned by PSO.
(c) In September 2018, management announced plans to close the plant by October 2020.

SWEPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mattison	4	AR	Natural Gas	315	2007
Stall	3	LA	Natural Gas	534	2010
Flint Creek (a)	1	AR	Steam - Coal	258	1978
Turk (a)	1	AR	Steam - Coal	477	2012
Welsh	2	TX	Steam - Coal	1,053	1977
Dolet Hills (a)(b)	1	LA	Steam - Lignite	257	1986
Pirkey (a)	1	TX	Steam - Lignite	580	1985
Arsenal Hill	1	LA	Steam - Natural Gas	110	1960
Knox Lee (c)(d)	4	TX	Steam - Natural Gas	404	1950
Lieberman (d)	3	LA	Steam - Natural Gas	242	1947
Lone Star (d)	1	TX	Steam - Natural Gas	50	1954
Wilkes	3	TX	Steam - Natural Gas	889	1964
Total MWs				5,169	

(a) Jointly-owned with nonaffiliated entities. Figures presented reflect only the portion owned by SWEPCo. The Arkansas jurisdictional portion of SWEPCo's interest in Turk Plant is not in rate base.
(b) In January 2020, management announced plans to close the plant at the end of 2026.
(c) Knox Lee Unit 4 was retired in January 2019. Figures presented include Unit 4 in the total.
(d) Knox Lee Unit 2 and Unit 3, Lieberman Unit 2 and Lone Star are scheduled for retirement in May 2020.

WPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mitchell (a)	2	WV	Steam - Coal	780	1971

(a) 17.5% of WPCo's interest in the Mitchell Plant units was not in rate base during 2019. In 2020 WPCo's entire interest in the Mitchell Plant will be in rate base. KPCo owns the remaining 50%. Figures presented reflect only the portion owned by WPCo.

Transmission and Distribution Segment

AEP Texas

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Oklaunion Power Station (a) (b) (c)	1	TX	Steam - Coal	355	1986

(a) Jointly-owned with PSO and nonaffiliated entities. Figures presented reflect only the portion owned by AEP Texas.
(b) In September 2018, management announced plans to close the plant by October 2020.
(c) The capacity and energy from the Oklaunion Power Station is sold to AEPEP under a PPA.

Generation & Marketing Segment

AGR

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Racine	2	OH	Hydro	48	1982
Cardinal	1	OH	Steam - Coal	595	1967
Conesville (a) (b)	1	OH	Steam - Coal	651	1957
Total MWs				1,294	

(a) Jointly-owned with nonaffiliated entities. Figures presented reflect only the portion owned by AGR.
(b) Conesville Plant Units 5 and 6 closed effective May 31, 2019 and Unit 4 is scheduled to close in May 2020.

Renewable Power

Size of Energy Resource	AEP Energy Supply, LLC Division	Renewable Energy Resource	Location	In-Service or Under Construction
1,212 MW	AEP Renewables	Wind	Eight states (a)	In-service
128 MW	AEP Renewables	Wind	Kansas	Under Construction
20 MW	AEP Renewables	Solar	California	In-service
20 MW	AEP Renewables	Solar	Utah	In-service
50 MW	AEP Renewables	Solar	Nevada	In-service
119 MW	AEP OnSite Partners	Solar	Fifteen states (b)	In-service
28 MW	AEP OnSite Partners	Solar	Three states (c)	Under Construction

(a) Colorado, Hawaii, Indiana, Kansas, Michigan, Minnesota, Pennsylvania, and Texas.
(b) California, Colorado, Florida, Hawaii, Iowa, Minnesota, Nebraska, New Hampshire, New Jersey, New Mexico, New York, Ohio, Rhode Island, Texas and Vermont.
(c) Illinois, New Mexico and Ohio.

In addition to the AGR and Renewable Power generation set forth above, a subsidiary in the Generation & Marketing segment has contractual rights through 2027 from AEP Texas to 355 MWs from the Oklaunion Power Station. AEP Texas co-owns the Oklaunion Power Station with PSO and several nonaffiliated entities. Management has announced plans to close Oklaunion Power Station by October 2020.

TRANSMISSION AND DISTRIBUTION FACILITIES

The following tables set forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies.

Vertically Integrated Utilities Segment

	Total Overhead Circuit Miles of Transmission and Distribution Lines
APCo	51,665
I&M	21,262
KGPCo	1,404
KPCo	11,138
PSO	18,234
SWEPCo	26,101
WPCo	1,740
Total Circuit Miles	131,544

Transmission and Distribution Utilities Segment

	Total Overhead Circuit Miles of Transmission and Distribution Lines
OPCo	44,944
AEP Texas	45,911
Total Circuit Miles	90,855

AEP Transmission Holdco Segment

The following table sets forth the total overhead circuit miles of transmission lines of certain wholly-owned and joint venture-owned entities:

	Total Overhead Circuit Miles of Transmission Lines
ETT	1,777
IMTCo	575
OHTCo	810
OKTCo	835
WVTCo	242
Pioneer	43
Prairie Wind Transmission	216
Transource Missouri	167
Transource West Virginia	24
Total Circuit Miles	4,689

TITLE TO PROPERTY

The AEP System's generating facilities are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the AEP System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of AEP's public utility subsidiaries in the realty on which their facilities are located are considered adequate for use in the conduct of their business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties. AEP's public utility subsidiaries generally have the right of eminent domain which permits them, if necessary, to acquire, perfect or secure titles to or easements on privately held lands used or to be used in their utility operations. Legislation in Ohio and Virginia has restricted the right of eminent domain previously granted for power generation purposes.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Tennessee, Texas, Virginia and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. AEP has experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes and in proceedings in which AEP's operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years.

CONSTRUCTION PROGRAM

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its transmission, distribution, generation and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available and assessments and plans are modified, as appropriate. AEP forecasts approximately $6.3 billion of construction expenditures for 2020. Capital expenditures related to North Central Wind Energy Facilities are excluded from this budgeted amount. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather and the ability to access capital. See the "Budgeted Capital Expenditures" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2019 Annual Report for additional information.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to AEP's generation plants and costs of replacement power. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could reduce net income and impact the financial conditions of AEP and other AEP System companies. For risks related to owning a nuclear generating unit, see the "Nuclear Contingencies" section of Note 6 - Commitments, Guarantees and Contingencies included in the 2019 Annual Report for additional information.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 6 - Commitments, Guarantees and Contingencies included in the 2019 Annual Report for additional information.

ITEM 4. MINE SAFETY DISCLOSURE

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. 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 December 31, 2019.

PART II

ITEM 5. MARKET FOR REGISTRANTS’ COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP

In addition to the discussion below, the remaining information required by this item is incorporated herein by reference to the material under AEP Common Stock Information and “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Dividend Policy and Restrictions” included in the 2019 Annual Report.

AEP Texas, APCo, I&M, OPCo, PSO and SWEPCo

The common stock of these companies is held solely by AEP. For more information see the “Dividend Restrictions” section of Note 14 - Financing Activities included in the 2019 Annual Report.

AEPTCo

AEP owns the entire interest in AEPTCo through its wholly-owned subsidiary AEP Transmission Holdco.

During the quarter ended December 31, 2019, neither AEP nor its publicly-traded subsidiaries purchased equity securities that are registered by AEP or its publicly-traded subsidiaries pursuant to Section 12 of the Exchange Act.

ITEM 6. SELECTED FINANCIAL DATA

AEP

The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the 2019 Annual Report.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(a). Management’s narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management’s Discussion and Analysis of Financial Condition and Results of Operations in the 2019 Annual Report.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

AEP

The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2019 Annual Report. Year-to-year comparisons between 2018 and 2017 have been omitted from this Form 10-K but may be found in "Management's Discussion and Analysis of Financial Condition" in Part II, Item 7 of our Form 10-K for the fiscal year ended December 31, 2018, which specific discussion is incorporated herein by reference.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2019 Annual Report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

The information required by this item is incorporated herein by reference to the material under the "Quantitative and Qualitative Disclosures About Market Risk" section of Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2019 Annual Report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Refer to AEP's 2019 Annual Reports, which are incorporated herein by reference. Also refer to the Index of Financial Statement Schedules on page S-1 of this Form 10-K.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Information required by this item is set forth under the caption Proposal to Ratify the Appointment of the Independent Registered Public Accounting Firm in the 2020 Proxy Statement, which is incorporated by reference into this item.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

During 2019, management, including the principal executive officer and principal financial officer of each of American Electric Power Company, Inc. ("AEP"), 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 (each a "Registrant" and collectively the "Registrants") evaluated each respective Registrant's disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrant 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 Commission'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 each Registrant's 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 December 31, 2019, the principal executive officer and financial officer of each of the Registrants concluded that the disclosure controls and procedures in place were effective at the reasonable assurance level. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

Changes in Internal Control over Financial Reporting

There have been no changes 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 fourth quarter 2019 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

Internal Control over Financial Reporting

See Management's Report on Internal Control over Financial Reporting for each Registrant under Item 8. As discussed in that report, management assessed and reported on the effectiveness of each Registrant's internal control over financial reporting as of December 31, 2019. As a result of that assessment, management concluded that each Registrant's internal control over financial reporting was effective as of December 31, 2019.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

AEP

Directors, Director Nomination Process and Audit Committee

Certain of the information called for in this Item 10, including the information relating to directors, is incorporated herein by reference to AEP's definitive proxy information statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2020 Annual Meeting of Shareholders (the 2020 Annual Meeting) including under the captions "Election of Directors," "AEP's Board of Directors and Committees," "Directors" and "Nominees for Directors."

Executive Officers

Reference also is made under the caption "Information About our Executive Officers" in Part I, Item 1 of this report.

Code of Ethics

AEP's Principles of Business Conduct is the code of ethics that applies to AEP's Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Principles of Business Conduct is available on AEP's website at www.aep.com. The Principles of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Investor Relations, American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215.

If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or principal accounting officer, AEP will disclose the nature of such amendment or waiver on AEP's website, www.aep.com, or in a report on Form 8-K.

Section 16(a) Beneficial Ownership Reporting Compliance

The information required by this item is incorporated herein by reference to information contained in the definitive proxy statement of AEP for the 2020 Annual Meeting.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 11. EXECUTIVE COMPENSATION

AEP

The information called for by this Item 11 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2020 Annual Meeting including under the captions "Compensation Discussion and Analysis," "Executive Compensation", "Director Compensation" and "2019 Director Compensation Table". The information set forth under the subcaption "Human Resources Committee Report" and "Audit Committee Report" should not be deemed filed nor should it be incorporated by reference into any other filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent AEP specifically incorporates such report by reference therein.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

AEP

The information relating to Security Ownership of Certain Beneficial Owners is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to 2020 Annual Meeting under the caption "Share Ownership of Certain Beneficial Owners and Management" and "Share Ownership of Directors and Executive Officers."

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes the ability of AEP to issue common stock pursuant to equity compensation plans as of December 31, 2019:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity Compensation Plans Approved by Security Holders	3,011,366	—	7,667,922
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	3,011,366	—	7,667,922

(a) The balance includes unvested 2019 performance shares and restricted stock units as well as vested performance shares deferred as AEP career shares, all of which will be settled and paid in shares of AEP common stock. For performance shares, the total includes the target number of shares that could be granted if performance meets target objectives. The number of securities that would be granted, with respect to performance shares, if performance meets the maximum payout level, is two times the amount included in this total.

(b) No consideration is required from participants for the exercise or vesting of any outstanding AEP equity compensation awards.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

AEP

The information called for by this Item 13 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2020 Annual Meeting under the captions "Transactions with Related Persons" and "Director Independence."

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP

The information called for by this Item 14 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2020 Annual Meeting under the captions "Audit and Non-Audit Fees," "Audit Committee Report" and "Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Auditor."

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Each of the above is a wholly-owned subsidiary of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2020 Annual Meeting of shareholders. The following table presents directly billed fees for professional services rendered by PricewaterhouseCoopers LLP for the audit of these companies' annual financial statements for the years ended December 31, 2019 and 2018, and fees directly billed for other services rendered by PricewaterhouseCoopers LLP during those periods. PricewaterhouseCoopers LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the description of principal accounting fees and services for AEP above.

	AEP Texas		AEPTCo		APCo	
	2019	2018	2019	2018	2019	2018
Audit Fees	$ 1,383,288	$ 1,129,561	$ 1,282,508	$ 1,193,523	$ 1,684,045	$ 1,721,299
Audit-Related Fees	132,667	76,000	—	—	70,904	42,571
Tax Fees	27,092	34,880	31,009	33,001	39,326	52,714
All Other Fees	—	13,247	—	12,534	—	40,530
Total	$ 1,543,047	$ 1,253,688	$ 1,313,517	$ 1,239,058	$ 1,794,275	$ 1,857,114

	I&M		OPCo		PSO	
	2019	2018	2019	2018	2019	2018
Audit Fees	$ 1,336,192	$ 1,510,574	$ 1,056,377	$ 1,093,392	$ 575,734	$ 603,527
Audit-Related Fees	10,071	10,071	10,071	48,071	4,571	4,571
Tax Fees	35,073	43,472	26,384	34,019	15,093	19,475
All Other Fees	—	24,715	—	12,920	—	21,415
Total	$ 1,381,336	$ 1,588,832	$ 1,092,832	$ 1,188,402	$ 595,398	$ 648,988

	SWEPCo	
	2019	2018
Audit Fees	$ 973,150	$ 1,150,091
Audit-Related Fees	24,571	24,571
Tax Fees	23,263	33,188
All Other Fees	—	29,131
Total	$ 1,020,984	$ 1,236,981

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this report:

1. FINANCIAL STATEMENTS:

The following financial statements have been incorporated herein by reference pursuant to Item 8.

AEP and Subsidiary Companies:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2019, 2018 and 2017; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2019, 2018 and 2017; Consolidated Statements of Changes in Equity for the years ended December 31, 2019, 2018 and 2017; Consolidated Balance Sheets as of December 31, 2019 and 2018; Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017; Notes to Financial Statements of Registrants.

AEP Texas, APCo, I&M and OPCo:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2019, 2018 and 2017; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2019, 2018 and 2017; Consolidated Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2019, 2018 and 2017; Consolidated Balance Sheets as of December 31, 2019 and 2018; Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017; Notes to Financial Statements of Registrants.

AEPTCo:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2019, 2018 and 2017; Consolidated Statements of Changes in Member's Equity for the years ended December 31, 2019, 2018 and 2017; Consolidated Balance Sheets as of December 31, 2019 and 2018; Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017; Notes to Financial Statements of Registrants.

PSO:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Statements of Income for the years ended December 31, 2019, 2018 and 2017; Statements of Comprehensive Income (Loss) for the years ended December 31, 2019, 2018 and 2017; Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2019, 2018 and 2017; Balance Sheets as of December 31, 2019 and 2018; Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017; Notes to Financial Statements of Registrants.

SWEPCo:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2019, 2018 and 2017; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2019, 2018 and 2017; Consolidated Statements of Changes in Equity for the years ended December 31, 2019, 2018 and 2017; Consolidated Balance Sheets as of December 31, 2019 and 2018; Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017; Notes to Financial Statements of Registrants.

2. **FINANCIAL STATEMENT SCHEDULES:**	**Page Number**
Financial Statement Schedules are listed in the Index of Financial Statement Schedules. (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Reports of Independent Registered Public Accounting Firm.	S-1
3. **EXHIBITS:**	
Exhibits for AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference.	E-1

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

American Electric Power Company, Inc.

By: /s/ Brian X. Tierney
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 20, 2020

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chairman of the Board, Chief Executive Officer and Director	February 20, 2020
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Executive Vice President and Chief Financial Officer	February 20, 2020
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	February 20, 2020
(iv) A Majority of the Directors:		
*Nicholas K. Akins *David J. Anderson *J. Barnie Beasley, Jr. *Ralph D. Crosby, Jr. *Art A. Garcia *Linda A. Goodspeed *Thomas E. Hoaglin *Sandra Beach Lin *Margaret M. McCarthy *Richard C. Notebaert *Lionel L. Nowell, III *Stephen S. Rasmussen *Oliver G. Richard, III *Sara Martinez Tucker		

*By: /s/ Brian X. Tierney
(Brian X. Tierney, Attorney-in-Fact)
February 20, 2020

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP Texas Inc.
Appalachian Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

By: /s/ Brian X. Tierney
(Brian X. Tierney, Vice President and Chief Financial Officer)

Date: February 20, 2020

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

	Signature	Title	Date
(i)	**Principal Executive Officer:**		
	/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chairman of the Board, Chief Executive Officer and Director	February 20, 2020
(ii)	**Principal Financial Officer:**		
	/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 20, 2020
(iii)	**Principal Accounting Officer:**		
	/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 20, 2020
(iv)	**A Majority of the Directors:**		
	*Nicholas K. Akins *Lisa M. Barton *Paul Chodak III *David M. Feinberg *Lana L. Hillebrand *Mark C. McCullough *Charles R. Patton Brian X. Tierney		

*By:	/s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**	February 20, 2020

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Indiana Michigan Power Company

By: /s/ Brian X. Tierney
(Brian X. Tierney, Vice President and Chief Financial Officer)

Date: February 20, 2020

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chairman of the Board, Chief Executive Officer and Director	February 20, 2020
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 20, 2020
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 20, 2020
(iv) A Majority of the Directors:		
*Nicholas K. Akins *Lisa M. Barton *Nicholas M. Elkins *Thomas A. Kratt *Marc E. Lewis *David A. Lucas *Mark C. McCullough *Carla E. Simpson *Toby L. Thomas Brian X. Tierney		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 20, 2020

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP Transmission Company, LLC

By: /s/ Brian X. Tierney
(Brian X. Tierney, Vice President, Chief Financial Officer, and Manager)

Date: February 20, 2020

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chairman of the Board, Chief Executive Officer and Manager	February 20, 2020
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Manager	February 20, 2020
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 20, 2020
(iv) A Majority of the Managers:		
*Nicholas K. Akins *David M. Feinberg *Mark C. McCullough *A. Wade Smith Brian X. Tierney		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 20, 2020

INDEX OF FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENT SCHEDULES

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

Our audits of the consolidated financial statements referred to in our report dated February 20, 2020 appearing in the 2019 Annual Report of American Electric Power Company, Inc. (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the accompanying schedule of condensed financial information as of December 31, 2019 and 2018 and for each of the three years in the period ended December 31, 2019 and schedule of valuation and qualifying accounts and reserves for each of the three years in the period ended December 31, 2019. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Affiliated Revenues	$ 11.0	$ 9.5	$ 9.1
Other Revenues	0.8	1.4	5.9
TOTAL REVENUES	11.8	10.9	15.0
EXPENSES			
Other Operation	53.2	39.7	35.9
Asset Impairments and Other Related Charges	—	9.3	—
Depreciation	0.2	0.3	0.3
TOTAL EXPENSES	53.4	49.3	36.2
OPERATING LOSS	(41.6)	(38.4)	(21.2)
Other Income (Expense):			
Interest Income	53.5	31.3	20.5
Interest Expense	(159.2)	(87.5)	(43.1)
LOSS BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	(147.3)	(94.6)	(43.8)
Income Tax Expense (Benefit)	22.8	(6.2)	0.1
Equity Earnings of Unconsolidated Subsidiaries	2,091.2	2,012.2	1,956.5
NET INCOME	1,921.1	1,923.8	1,912.6
Other Comprehensive Income (Loss)	(27.3)	(23.7)	88.5
TOTAL COMPREHENSIVE INCOME	$ 1,893.8	$ 1,900.1	$ 2,001.1
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	493,694,345	492,774,600	491,814,651
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.89	$ 3.90	$ 3.89
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	495,306,238	493,758,277	492,611,067
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.88	$ 3.90	$ 3.88

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31,	
	2019	**2018**
CURRENT ASSETS		
Cash and Cash Equivalents	$ 156.1	$ 99.3
Other Temporary Investments	2.0	2.3
Advances to Affiliates	2,197.9	1,096.4
Accounts Receivable:		
Affiliated Companies	11.3	6.4
General	0.3	7.6
Total Accounts Receivable	11.6	14.0
Affiliated Notes Receivable	20.0	—
Accrued Tax Benefits	7.1	—
Prepayments and Other Current Assets	9.9	2.5
TOTAL CURRENT ASSETS	2,404.6	1,214.5
PROPERTY, PLANT AND EQUIPMENT		
General	2.3	2.2
Construction Work in Progress	0.2	—
Total Property, Plant and Equipment	2.5	2.2
Accumulated Depreciation, Depletion and Amortization	1.4	1.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1.1	1.0
OTHER NONCURRENT ASSETS		
Investments in Unconsolidated Subsidiaries	23,329.9	21,522.3
Affiliated Notes Receivable	39.0	50.0
Deferred Charges and Other Noncurrent Assets	95.7	114.1
TOTAL OTHER NONCURRENT ASSETS	23,464.6	21,686.4
TOTAL ASSETS	$ 25,870.3	$ 22,901.9

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2019 and 2018
(dollars in millions)

		December 31,		
		2019		**2018**
CURRENT LIABILITIES				
Advances from Affiliates	$	252.6	$	313.6
Accounts Payable:				
General		0.5		5.9
Affiliated Companies		8.4		4.2
Short-term Debt		2,110.0		1,160.0
Long-term Debt Due Within One Year – Nonaffiliated (a)		501.9		(2.0)
Accrued Taxes		44.2		13.2
Other Current Liabilities		38.1		16.5
TOTAL CURRENT LIABILITIES		2,955.7		1,511.4
NONCURRENT LIABILITIES				
Long-term Debt – Nonaffiliated (a)		3,122.9		2,268.4
Deferred Credits and Other Noncurrent Liabilities		116.6		54.3
TOTAL NONCURRENT LIABILITIES		3,239.5		2,322.7
TOTAL LIABILITIES		6,195.2		3,834.1
MEZZANINE EQUITY				
Contingently Redeemable Performance Share Awards		42.9		39.4
COMMON SHAREHOLDERS' EQUITY				
Common Stock – Par Value – $6.50 Per Share:				

	2019	2018
Shares Authorized	600,000,000	600,000,000
Shares Issued	514,373,631	513,450,036

		2019		2018
(20,204,160 Shares were Held in Treasury as of December 31, 2019 and 2018, Respectively)		3,343.4		3,337.4
Paid-in Capital		6,535.6		6,486.1
Retained Earnings		9,900.9		9,325.3
Accumulated Other Comprehensive Income (Loss)		(147.7)		(120.4)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY		19,632.2		19,028.4
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY	$	25,870.3	$	22,901.9

(a) Amounts reflect the impact of fair value hedge accounting. See "Accounting for Fair Value Hedging Strategies" section of Note 10 included in the 2019 Annual Reports for additional information.

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 1,921.1	$ 1,923.8	$ 1,912.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	0.2	0.3	0.3
Deferred Income Taxes	26.5	(45.0)	33.7
Asset Impairments and Other Related Charges	—	9.3	—
Equity Earnings of Unconsolidated Subsidiaries	(2,091.2)	(2,012.2)	(1,956.5)
Cash Dividends Received from Unconsolidated Subsidiaries	426.2	855.6	827.0
Change in Other Noncurrent Assets	0.1	(5.5)	(0.4)
Change in Other Noncurrent Liabilities	84.5	42.1	74.0
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	2.4	(3.9)	51.5
Accounts Payable	(1.2)	—	1.6
Other Current Assets	(0.8)	47.8	70.0
Other Current Liabilities	36.4	4.7	0.7
Net Cash Flows from Operating Activities	404.2	817.0	1,014.5
INVESTING ACTIVITIES			
Construction Expenditures	(0.3)	(0.4)	(0.7)
Change in Advances to Affiliates, Net	(1,101.5)	(106.9)	(76.4)
Capital Contributions to Unconsolidated Subsidiaries	(212.8)	(859.1)	(563.2)
Return of Capital Contributions from Unconsolidated Subsidiaries	70.9	199.7	263.3
Issuance of Notes Receivable to Affiliated Companies	(9.0)	—	(30.0)
Net Cash Flows Used for Investing Activities	(1,252.7)	(766.7)	(407.0)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	65.3	73.6	12.2
Issuance of Long-term Debt	1,321.3	991.9	992.3
Commercial Paper and Credit Facility Borrowings	—	205.6	—
Change in Short-term Debt, Net	950.0	261.4	(141.4)
Retirement of Long-term Debt	—	—	(550.0)
Change in Advances from Affiliates, Net	(61.0)	(151.5)	266.7
Commercial Paper and Credit Facility Repayments	—	(205.6)	—
Dividends Paid on Common Stock	(1,345.5)	(1,251.1)	(1,175.4)
Other Financing Activities	(24.8)	(7.4)	(5.1)
Net Cash Flows from (Used for) Financing Activities	905.3	(83.1)	(600.7)
Net Increase (Decrease) in Cash and Cash Equivalents	56.8	(32.8)	6.8
Cash and Cash Equivalents at Beginning of Period	99.3	132.1	125.3
Cash and Cash Equivalents at End of Period	$ 156.1	$ 99.3	$ 132.1

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL INFORMATION

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The condensed financial information of Parent is required as a result of the restricted net assets of AEP consolidated subsidiaries exceeding 25% of AEP consolidated net assets as of December 31, 2019. Parent is a public utility holding company that owns all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries, including joint ventures and equity investments. The primary source of income for Parent is equity in its subsidiaries' earnings. Its major source of cash is dividends from the subsidiaries. Parent borrows the funds for the money pool that is used by the subsidiaries for their short-term cash needs.

Income Taxes

Parent files a consolidated federal income tax return with its subsidiaries. AEP System's current consolidated federal income tax is allocated to AEP System companies so that their current tax expense reflects a separate return result for each company in the consolidated group. The tax benefit of Parent is allocated to its subsidiaries with taxable income.

2. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Parent and its subsidiaries are parties to environmental and other legal matters. For further discussion, see Note 6 - Commitments, Guarantees and Contingencies included in the 2019 Annual Report.

3. FINANCING ACTIVITIES

The following details long-term debt outstanding as of December 31, 2019 and 2018:

Long-term Debt

Type of Debt	Maturity	Weighted-Average Interest Rate as of December 31, 2019	Interest Rate Ranges as of December 31, 2019	Interest Rate Ranges as of December 31, 2018	Outstanding as of December 31, 2019	Outstanding as of December 31, 2018
					(in millions)	
Senior Unsecured Notes	2020-2028	3.30%	2.15%-4.30%	2.15%-4.30%	$ 2,301.5	$ 2,266.4
Pollution Control Bonds	2024-2029	2.26%	1.90%-2.60%		535.5	—
Junior Subordinate Notes	2022	3.40%	3.40%		787.8	—
Total Long-term Debt Outstanding					3,624.8	2,266.4
Long-term Debt Due Within One Year					501.9	—
Long-term Debt					$ 3,122.9	$ 2,266.4

Long-term debt outstanding as of December 31, 2019 is payable as follows:

	2020	2021	2022	2023	2024	After 2024	Total
				(in millions)			
Principal Amount (a)	$ 501.9	$ 402.8	$ 1,107.6	$ 2.4	$ 300.9	$ 1,342.9	$ 3,658.5
Unamortized Discount, Net and Debt Issuance Costs							(33.7)
Total Long-term Debt Outstanding							$ 3,624.8

(a) Amounts reflect the impact of fair value hedge accounting. See "Accounting for Fair Value Hedging Strategies" section of Note 10 included in the 2019 Annual Report for additional information.

Short-term Debt

Parent's outstanding short-term debt was as follows:

	December 31, 2019		December 31, 2018	
Type of Debt	**Outstanding Amount**	**Weighted-Average Interest Rate**	**Outstanding Amount**	**Weighted-Average Interest Rate**
	(in millions)		**(in millions)**	
Commercial Paper	$ 2,110.0	2.10%	$ 1,160.0	2.96%
Total Short-term Debt	$ 2,110.0		$ 1,160.0	

4. RELATED PARTY TRANSACTIONS

Payments on Behalf of Subsidiaries

Due to occasional time sensitivity and complexity of payments, Parent makes certain insurance, tax and benefit payments on behalf of subsidiary companies. Parent is then fully reimbursed by the subsidiary companies.

Short-term Lending to Subsidiaries

Parent uses a commercial paper program to meet the short-term borrowing needs of subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The program also allows some direct borrowers to invest excess cash with Parent.

Interest expense related to Parent's short-term borrowing is included in Interest Expense on Parent's statements of income. Parent incurred interest expense for amounts borrowed from subsidiaries of $8 million, $11 million and $8 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Interest income related to Parent's short-term lending is included in Interest Income on Parent's statements of income. Parent earned interest income for amounts advanced to subsidiaries of $49 million, $27 million and $16 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Affiliated Notes

Parent issued long-term debt, portions of which were loaned to its subsidiaries. Parent pays interest on the affiliated notes, but the subsidiaries accrue interest for their share of the affiliated borrowing and remit the interest to Parent. Interest income related to Parent's loans to subsidiaries is included in Interest Income on Parent's statements of income. Parent earned interest income on loans to subsidiaries of $2 million, $2 million and $2 million for the years ended December 31, 2019, 2018 and 2017, respectively.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

AEP

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in millions)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2019	$ 36.8	$ 41.3	$ 3.6	$ 38.0	$ 43.7
Year Ended December 31, 2018	38.5	37.3	2.6	41.6	36.8
Year Ended December 31, 2017	37.9	34.0	2.5	35.9	38.5

(a) Recoveries offset by reclasses to other assets and liabilities.
(b) Uncollectible accounts written off.

Schedule II for the Registrant Subsidiaries is not presented because the amounts are not material.

INDEX OF AEP TRANSMISSION COMPANY, LLC (AEPTCO PARENT)
FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Member of
AEP Transmission Company, LLC

Our audits of the consolidated financial statements referred to in our report dated February 20, 2020 appearing in the 2019 Annual Report of AEP Transmission Company, LLC (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the accompanying schedule of condensed financial information as of December 31, 2019 and 2018 and for each of the three years in the period ended December 31, 2019. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
EXPENSES			
Other Operation	$ 0.3	$ —	$ —
TOTAL EXPENSES	0.3	—	—
OPERATING LOSS	(0.3)	—	—
Other Income (Expense):			
Interest Income - Affiliated	123.8	104.6	82.9
Interest Expense	(122.1)	(103.4)	(82.4)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS OF UNCONSOLIDATED SUBSIDIARIES	1.4	1.2	0.5
Income Tax Expense	0.3	0.2	0.2
Equity Earnings of Unconsolidated Subsidiaries	438.6	314.9	270.4
NET INCOME	$ 439.7	$ 315.9	$ 270.7

See Condensed Notes to Condensed Financial Information beginning on page S-17.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31,	
	2019	**2018**
CURRENT ASSETS		
Advances to Affiliates	$ 68.7	$ 17.0
Accounts Receivable:		
Affiliated Companies	23.1	17.1
Total Accounts Receivable	23.1	17.1
TOTAL CURRENT ASSETS	91.8	34.1
OTHER NONCURRENT ASSETS		
Notes Receivable - Affiliated	3,427.3	2,823.0
Investments in Unconsolidated Subsidiaries	4,009.7	3,571.1
TOTAL OTHER NONCURRENT ASSETS	7,437.0	6,394.1
TOTAL ASSETS	$ 7,528.8	$ 6,428.2

See Condensed Notes to Condensed Financial Information beginning on page S-17.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2019 and 2018
(in millions)

	December 31,	
	2019	**2018**
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 35.6	$ 0.3
Affiliated Companies	35.0	17.7
Long-term Debt Due Within One Year – Nonaffiliated	—	85.0
Accrued Taxes	—	0.1
Accrued Interest	19.2	15.9
Other Current Liabilities	2.2	1.4
TOTAL CURRENT LIABILITIES	92.0	120.4
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,427.3	2,738.0
TOTAL NONCURRENT LIABILITIES	3,427.3	2,738.0
TOTAL LIABILITIES	3,519.3	2,858.4
MEMBER'S EQUITY		
Paid-in Capital	2,480.6	2,480.6
Retained Earnings	1,528.9	1,089.2
TOTAL MEMBER'S EQUITY	4,009.5	3,569.8
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 7,528.8	$ 6,428.2

See Condensed Notes to Condensed Financial Information beginning on page S-17.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 439.7	$ 315.9	$ 270.7
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:			
Deferred Income Taxes	—	—	1.6
Equity Earnings of Unconsolidated Subsidiaries	(438.6)	(314.9)	(270.4)
Change in Other Noncurrent Liabilities	11.9	—	—
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(6.0)	0.2	4.5
Accounts Payable	18.8	(6.4)	5.4
Accrued Taxes, Net	(0.1)	—	0.1
Accrued Interest	3.3	0.9	4.5
Other Current Liabilities	34.7	(1.2)	(8.1)
Net Cash Flows from (Used for) Operating Activities	63.7	(5.5)	8.3
INVESTING ACTIVITIES			
Change in Advances to Affiliates, Net	(51.7)	5.5	(8.3)
Issuance of Notes Receivable to Affiliated Companies	(615.0)	(271.0)	(617.6)
Capital Contributions to Subsidiaries	—	(664.0)	(361.6)
Net Cash Flows Used for Investing Activities	(666.7)	(929.5)	(987.5)
FINANCING ACTIVITIES			
Capital Contributions from Member	—	664.0	361.6
Issuance of Long-term Debt – Nonaffiliated	688.0	321.0	617.6
Retirement of Long-term Debt – Nonaffiliated	(85.0)	(50.0)	—
Net Cash Flows from Financing Activities	603.0	935.0	979.2
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of Period	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ —

See Condensed Notes to Condensed Financial Information beginning on page S-17.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL INFORMATION

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The condensed financial information of AEPTCo Parent is required as a result of the restricted net assets of AEPTCo consolidated subsidiaries exceeding 25% of AEPTCo consolidated net assets as of December 31, 2019. AEPTCo Parent is the direct holding company for the seven State Transcos. The primary source of income for AEPTCo Parent is equity in its subsidiaries' earnings. AEPTCo Parent financial statements should be read in conjunction with the AEPTCo consolidated financial statements and the accompanying notes thereto. For purposes of these condensed financial statements, AEPTCo wholly owned and majority owned subsidiaries are recorded based upon its proportionate share of the subsidiaries' net assets (similar to presenting them on the equity method).

Income Taxes

AEPTCo Parent joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses ("Parent Company Loss Benefit") to the AEP System companies giving rise to such losses in determining their current tax expense. The consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of AEP Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss, the loss of the AEP Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

2. COMMITMENTS, GUARANTEES AND CONTINGENCIES

AEPTCo Parent and its subsidiaries are parties to legal matters. For further discussion, see Note 6 - Commitments, Guarantees and Contingencies included in the 2019 Annual Report.

3. FINANCING ACTIVITIES

For discussion of Financing Activities, see Note 14 - Financing Activities to AEPTCo's audited consolidated financial statements included in the 2019 Annual Report.

4. RELATED PARTY TRANSACTIONS

Payments on Behalf of Subsidiaries

Due to occasional time sensitivity and complexity of payments, Parent makes certain insurance, tax and other payments on behalf of subsidiary companies. Parent is then fully reimbursed by the subsidiary companies. AEPTCo Parent also makes convenience payments on behalf of its State Transcos. AEPTCo Parent is then fully reimbursed by its State Transcos.

Long-term Lending to Subsidiaries

AEPTCo Parent enters into debt arrangements with nonaffiliated entities. AEPTCo Parent has long-term debt of $3.4 billion and $2.8 billion as of December 31, 2019 and 2018, respectively. AEPTCo Parent uses the proceeds from these nonaffiliated debt arrangements to make affiliated loans to its State Transcos using the same interest rates and maturity dates as the nonaffiliated debt arrangements. AEPTCo Parent has recorded Notes Receivable – Affiliated of $3.4 billion and $2.8 billion as of December 31, 2019 and 2018, respectively. Related to these nonaffiliated and affiliated debt arrangements, AEPTCo Parent has recorded Accrued Interest of $19 million and $16 million as of December 31, 2019 and 2018, respectively. AEPTCo Parent has also recorded Accounts Receivable – Affiliated Companies of $23 million and $17 million as of December 31, 2019 and 2018, respectively. AEPTCo Parent has recorded Interest Income – Affiliated of $124 million, $105 million and $83 million for the years ended December 31, 2019, 2018 and 2017, respectively, related to the Notes Receivable – Affiliated. AEPTCo Parent has recorded Interest Expense of $122 million, $103 million and $82 million for the years ended December 31, 2019, 2018 and 2017, respectively, related to the nonaffiliated debt arrangements.

Short-term Lending to Subsidiaries

Parent uses a commercial paper program to meet the short-term borrowing needs of subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The program also allows some direct borrowers to invest excess cash with Parent.

Interest expense related to AEPTCo Parent's short-term borrowing is included in Interest Expense on AEPTCo Parent's statements of income. AEPTCo Parent incurred immaterial interest expense for amounts borrowed from AEP affiliates for the years ended December 31, 2019, 2018 and 2017.

Interest income related to AEPTCo Parent's short-term lending is included in Interest Income – Affiliated on AEPTCo Parent's statements of income. AEPTCo Parent earned interest income for amounts advanced to AEP affiliates of $2 million, $1 million and $1 million for the year ended December 31, 2019, 2018 and 2017, respectively.

EXHIBIT INDEX

The documents listed below are being filed or 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. Exhibits ("Ex") not identified as previously filed are filed herewith. Exhibits designated with a dagger (†) are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form. Exhibits designated with an asterisk (*) are filed herewith.

AEP‡ File No. 1-3525

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated April 26, 2019.	Form 10-Q, Ex 3, June 30, 2019
3(b)	Composite By-Laws of AEP, as amended as of October 20, 2015.	Form 8-K, Ex 3(b) dated October 21, 2015
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c) Registration Statement No. 333-105532, Ex 4(d)(e)(f) Registration Statement No. 333-200956, Ex 4(b) Registration Statement No. 333-222068, Ex 4(b)
4(a)1	Company Order and Officers Certificate to The Bank of New York Mellon Trust Company, N.A. dated November 30, 2018 of 3.65% Senior Notes Series I due 2021 and 4.30% Senior Notes, Series J due 2028.	Form 8-K, Ex. 4(a) dated November 30, 2018
4(a)3	Purchase Contract and Pledge Agreement, dated as of March 19, 2019, between the Company and The Bank of New York Mellon Trust Company, N.A., as purchase contract agent, collateral agent, custodial agent and securities intermediary.	Form 8-K, Ex 4.1 dated March 19, 2019
4(a)4	Junior Subordinated Indenture, dated March 1, 2008, between the Company and The Bank of New York Mellon Trust Company, N.A., as Trustee for the Junior Subordinated Debentures.	Registration Statement No 333-156387, Ex 4(c)
4(a)5	Supplemental Indenture No. 1, dated March 19, 2019, from the Company to The Bank of New York Mellon Trust Company, N.A., as trustee.	Form 8-K, Ex 4.3 dated March 19, 2019
4(b)	First Amendment to Fourth Amended and Restated Credit Agreement dated June 30, 2016 among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof and Wells Fargo Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 4, September 30, 2018
*4(c)	Description of Securities.	
10(a)	Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C) Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) AEGCo 1993 Form 10-K, Ex 10(c)(1-6)(B) I&M 1993 Form 10-K, Ex 10(e)(1-6)(B)
10(b)	Consent Decree with U.S. District Court dated October 9, 2007, as modified July 17, 2019.	Form 8-K, Ex. 10 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013 Form 10-Q, Ex 10, June 30, 2019
†10(c)	AEP Retainer Deferral Plan for Non-Employee Directors, as Amended and Restated effective July 26, 2016.	2016 Form 10-K, Ex 10(h)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(d)	AEP Stock Unit Accumulation Plan for Non-Employee Directors as amended July 26, 2016.	2016 Form 10-K, Ex 10(i)
*†10(e)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2020.	
†10(e)(1)	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
†10(f)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2011 (Non-Qualified).	2010 Form 10-K, Ex 10
†10(f)(1)(A)	Amendment to AEP System Supplemental Retirement Savings Plan, as Amended and Restated as of January 1, 2011 (Non-Qualified).	2014 Form 10-K, Ex 10(l)(1)(A)
*†10(f)(2)(A)	Second Amendment to AEP System Supplemental Retirement Savings Plan, as Amended and Restated as of January 1, 2011 (Non-Qualified).	
†10(g)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3)
†10(g)(1)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(l)(3)(A)
†10(g)(2)(A)	Second Amendment to AEPSC Umbrella Trust for Executives.	2018 Form 10-K, Ex 10(g)(2)(A)
†10(h)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of June 1, 2019.	Form 10-Q, Ex 10(1), September 30, 2019
†10(h)(1)(A)	First Amendment to AEP System Incentive Compensation Deferral Plan, as Amended and Restated effective January 1, 2008.	2011 Form 10-K, Ex 10(p)(1)(A)
†10(h)(2)(A)	Second Amendment to AEP System Incentive Compensation Deferral Plan, as Amended and Restated effective January 1, 2008.	2014 Form 10-K, Ex 10(q)(2)(A)
†10(i)	AEP Change In Control Agreement, as Revised Effective January 1, 2017.	Form 10-Q, Ex 10(c) , September 30, 2016
†10(j)	Amended and Restated AEP System Long-Term Incentive Plan as of September 21, 2016.	Form 10-Q, Ex 10(a) , September 30, 2016
†10(j)(1)(A)	Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(a), March 30, 2018
†10(j)(2)(A)	Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan as Amended and Restated.	Form 10-Q, Ex 10(b), March 30, 2018
†10(k)	AEP System Stock Ownership Requirement Plan Amended and Restated effective June 20, 2017.	Form 10-Q, Ex 10, June 30, 2017
*†10(l)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2020.	
†10(m)	AEP Executive Severance Plan Amended and Restated effective October 24, 2016.	Form 10-Q, Ex 10(d) , September 30, 2016
†10(n)	Letter Agreement dated November 20, 2012 between AEPSC and Lana Hillebrand.	2013 Form 10-K, Ex 10(x)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(o)	AEP Aircraft Timesharing Agreement dated October 1, 2019 between American Electric Power Service Corporation and Nicholas K. Akins.	Form 10-Q, Ex 10(2), September 30, 2019
*13	Copy of those portions of the AEP 2019 Annual Report (for the fiscal year ended December 31, 2019) which are incorporated by reference in this filing.	
*21	List of subsidiaries of AEP.	
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
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.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
AEP TEXAS‡ File No. 333-221643		
3(a)	Composite of the Restated Certificate of Incorporation, as amended.	Registration No. 333-221643, Ex 3(a)
3(b)	Bylaws.	Registration No. 333-221643, Ex 3(b)
4(a)(1)	Indenture, dated as of September 1, 2017, between AEP Texas Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Registration No. 333-221643, Ex 4(a)-1,4(a)-2; Registration No. 333-228657, Ex 4(a)-4,4(a)-5; Registration No. 333-230613, Ex 4(a)(b)
4(a)(2)	Company Order and Officer's Certificate to The Bank of New York Mellon Trust Company, N.A. December 5, 2019 of 3.45% Senior Notes, Series H due 2050.	Form 8-K Ex 4(a) dated December 6, 2019

*13	Copy of those portions of the AEP Texas 2019 Annual Report (for the fiscal year ended December 31, 2019) which are incorporated by reference in this filing.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
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104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
AEPTCo‡ File No. 333-217143		
3(a)	Limited Liability Company Agreement of AEP Transmission Company, LLC dated as of January 27, 2006.	Registration Statement No. 333-217143, Ex 3(a)
3(b)	First Amendment to Limited Liability Company Agreement dated as of May 21, 2013.	Registration Statement No. 333-217143, Ex 3(b)
4(a)(1)	Indenture, dated as of November 1, 2016, between AEP Transmission Company, LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Registration Statement No. 333-217143, Ex 4(a)-1, 4(a)-2 Registration Statement No. 333-225325, Ex 4(b)(c)(d)
4(a)(2)	Company Order and Officers' Certificate to The Bank of New York Mellon Trust Company, N.A. dated September 7, 2018 establishing the terms of the 4.25% Senior Notes, Series J due 2048.	Form 8-K, Ex 4(a) dated September 7, 2018
4(a)(3)	Company Order and Officers' Certificate to The Bank of New York Mellon Trust Company, N.A. dated June 12, 2019 establishing the terms of the 3.80% Senior Notes, Series K due 2049.	Form 8-K Ex 4(a) dated June 12, 2019
4(a)(4)	Company Order and Officers' Certificate to The Bank of New York Mellon Trust Company, N.A. dated September 11, 2019 establishing the terms of the 3.15% Senior Notes, Series L due 2049.	Form 8-K Ex 4(a) dated September 9, 2019

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(c)(1)	Note Purchase Agreement, dated as of October 18, 2012 between AEP Transmission Company, LLC and the Initial Purchasers.	Registration Statement No. 333-217143, Ex 4(c)-1
4(c)(2)	Supplement to Note Purchase Agreement, dated as of November 7, 2013 between AEP Transmission Company, LLC and the Initial Purchasers.	Registration Statement No. 333-217143, Ex 4(c)-2
4(c)(3)	Supplement to Note Purchase Agreement, dated as of November 14, 2014 between AEP Transmission Company, LLC and the Initial Purchasers.	Registration Statement No. 333-217143, Ex 4(c)-3
*13	Copy of those portions of the AEPTCo 2019 Annual Report (for the fiscal year ended December 31, 2019) which are incorporated by reference in this filing.	
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
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104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
APCo‡ File No. 1-3457		
3(a)	Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.	1996 Form 10-K, Ex 3(d)
3(b)	Composite By-Laws of APCo, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(a)	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee.	Registration Statement No. 333-45927, Ex 4(a)(b) Registration Statement No. 333-49071, Ex 4(b) Registration Statement No. 333-84061, Ex 4(b)(c) Registration Statement No. 333-100451, Ex 4(b) Registration Statement No. 333-116284, Ex 4(b)(c) Registration Statement No. 333-123348, Ex 4(b)(c) Registration Statement No. 333-136432, Ex 4(b)(c)(d) Registration Statement No. 333-161940, Ex 4(b)(c)(d) Registration Statement No. 333-182336, Ex 4(b)(c) Registration Statement No. 333-200750, Ex. 4(b)(c) Registration Statement No. 333-214448, Ex. 4(b)
4(a)(1)	Company Order and Officers Certificate to The Bank of New York Mellon Trust Company, N.A. dated May 11, 2017 of 3.30% Senior Notes Series X due 2027.	Form 8-K, Ex 4(a) dated May 11, 2017
4(a)(2)	Company Order and Officers Certificate to The Bank of New York Mellon Trust Company, N.A. dated March 6, 2019 of 4.50% Senior Notes Series Y due 2049.	Form 8-K, Ex 4(a) dated March 6, 2019
10(a)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(d)	Consent Decree with U.S. District Court dated October 9, 2007, as modified July 17, 2019.	Form 8-K, Ex. 10 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013 Form 10-Q, Ex 10, June 30, 2019
*13	Copy of those portions of the APCo 2019 Annual Report (for the fiscal year ended December 31, 2019) which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
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Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
I&M‡ File No. 1-3570		
3(a)	Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997.	1996 Form 10-K, Ex 3(c)
3(b)	Composite By-Laws of I&M, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.	Registration Statement No. 333-88523, Ex 4(a)(b)(c) Registration Statement No. 333-58656, Ex 4(b)(c) Registration Statement No. 333-108975, Ex 4(b)(c)(d) Registration Statement No. 333-136538, Ex 4(b)(c) Registration Statement No. 333-156182, Ex 4(b) Registration Statement No. 333-185087, Ex 4(b) Registration Statement No. 333-207836, Ex 4(b) Registration Statement No. 333-225103, Ex 4(b)(c)(d)
4(b)	Company Order and Officers Certificate to The Bank of New York Mellon Trust Company, N.A. dated August 8, 2018 of 4.25% Series N due 2048.	Form 8-K, Ex 4(a) dated August 8, 2018
10(a)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(b)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B)
10(c)	Consent Decree with U.S. District Court dated October 9, 2007, as modified July 17, 2019.	Form 8-K, Ex. 10 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013 Form 10-Q, Ex 10, June 30, 2019
10(d)	Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) 1993 Form 10-K, Ex 10(e)(1-6)(B)
*13	Copy of those portions of the I&M 2019 Annual Report (for the fiscal year ended December 31, 2019) which are incorporated by reference in this filing.	
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	

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104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
OPCo‡ File No.1-6543		
3(a)	Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.	Form 10-Q, Ex 3(e), June 30, 2002
3(b)	Amended Code of Regulations of OPCo.	Form 10-Q, Ex 3(b), June 30, 2008
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now The Bank of New York Mellon Trust Company, N.A. as assignee of Deutsche Bank Trust Company Americas), as Trustee.	Registration Statement No. 333-49595, Ex 4(a)(b)(c) Registration Statement No. 333-106242, Ex 4(b)(c)(d) Registration Statement No. 333-127913, Ex 4(b)(c) Registration Statement No. 333-139802, Ex 4(b)(c)(d) Registration Statement No. 333-161537, Ex 4(b)(c)(d) Registration Statement No. 333-211192, Ex 4(b) Registration Statement No. 333-230094, Ex 4(b)
4a(1)	Resignation of Deutsche Bank Trust Company Americas, as Trustee and appointment of The Bank of New York Mellon Trust Company, N.A. as Trustee of Indenture with OPCo dated as of September 1, 1997.	Form 8-K, Item 8.01 dated October 8, 2018
4(c)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.	Registration Statement No. 333-127913, Ex 4(d)(e)(f)
4(d)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo (predecessor in interest to OPCo) and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d) Registration Statement No. 333-128174, Ex 4(b)(c)(d) Registration Statement No. 333-150603, Ex 4(b)
4(e)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo (predecessor in interest to OPCo) and Bank One, N.A., as Trustee.	Registration Statement No. 333-128174, Ex 4(e)(f)(g) Registration Statement No. 333-150603, Ex 4(b)
4(f)	First Supplemental Indenture, dated as of December 31, 2011, by and between OPCo and The Bank of New York Mellon Trust Company, N.A., as trustee, supplementing the Indenture dated as of September 1, 1997 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.1 dated January 6, 2012
4(g)	Third Supplemental Indenture, dated as of December 31, 2011, by and between OPCo and The Bank of New York Mellon Trust Company, N.A., as trustee, supplementing the Indenture dated as of February 14, 2003 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.2 dated January 6, 2012

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(h)	Company Order and Officers Certificate to The Bank of New York Mellon Trust Company, N.A. dated May 22, 2019 of 4.00% Series O due 2049.	Form 8-K, Ex 4(a) dated May 22, 2019
10(a)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(b)	Consent Decree with U.S. District Court dated October 9, 2007, as modified July 17, 2019.	Form 8-K, Ex. 10 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013 Form 10-Q, Ex 10, June 30, 2019
*13	Copy of those portions of the OPCo 2019 Annual Report (for the fiscal year ended December 31, 2019) which are incorporated by reference in this filing.	
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
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104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
PSO‡ File No. 0-343		
3(a)	Certificate of Amendment to Restated Certificate of Incorporation of PSO.	Form 10-Q, Ex 3(a), June 30, 2008
3(b)	Composite By-Laws of PSO amended as of February 26, 2008.	2007 Form 10-K, Ex 3 (b)
4(a)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Ex 4(a)(b) Registration Statement No. 333-114665, Ex 4(b)(c) Registration Statement No. 333-133548, Ex 4(b)(c)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(b)	Eighth Supplemental Indenture, dated as of November 13, 2009 between PSO and The Bank of New York Mellon, as Trustee, establishing terms of the 5.15% Senior Notes, Series H, due 2019.	Form 8-K, Ex 4(a), dated November 13, 2009
4(c)	Ninth Supplemental Indenture, dated as of January 19, 2011 between PSO and The Bank of New York Mellon Trust Company, N.A., as Trustee, establishing terms of 4.40% Senior Notes, Series I, due 2021.	Form 8-K, Ex 4(a) dated January 20, 2011
*13	Copy of those portions of the PSO 2019 Annual Report (for the fiscal year ended December 31, 2019) which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
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101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
104	Cover Page Interactive Data File. Formatted as inline XBRL and contained in Exhibit 101.	
SWEPCo‡ File No. 1-3146		
3(a)	Composite of Amended Restated Certificate of Incorporation of SWEPCo.	2008 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of SWEPCo amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-96213 Registration Statement No. 333-87834, Ex 4(a)(b) Registration Statement No. 333-100632, Ex 4(b) Registration Statement No. 333-108045, Ex 4(b) Registration Statement No. 333-145669, Ex 4(c)(d) Registration Statement No. 333-161539, Ex 4(b)(c) Registration Statement No. 333-194991, Ex 4(b)(c) Registration Statement No. 333-208535, Ex 4(b)(c) Registration Statement No. 333-226856, Ex 4(b)(c)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(b)	Thirteenth Supplemental Indenture, dated as of September 1, 2018 between SWEPCo and The Bank of New York Mellon Trust Company, N.A., as Trustee, establishing terms of the 4.10% Senior Notes, Series M. Due 2028.	Form 8-K, Ex 4(a) dated September 13, 2018
*13	Copy of those portions of the SWEPCo 2019 Annual Report (for the fiscal year ended December 31, 2019) which are incorporated by reference in this filing.	
*23	Consent of PricewaterhouseCoopers LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*95	Mine Safety Disclosure.	
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‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

The agreements and other documents filed as exhibits to this report are not intended to provide factual information or other disclosure other than with respect to the terms of the agreements or other documents themselves, and you should not rely on them for that purpose. In particular, any representations and warranties made by us in these agreements or other documents were made solely within the specific context of the relevant agreement or document and may not describe the actual state of affairs as of the date they were made or at any other time.

Exhibit 4(c). Description of Securities.

As of the date of the Annual Report on Form 10-K of which this exhibit is a part, American Electric Power Company, Inc. (the "Company") has two classes of securities registered under Section 12(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"): (1) our common stock, par value $6.50 per share, and (2) our 6.125% Equity Units.

Description of Common Stock

The following description of our common stock is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to our Amended and Restated Certificate of Incorporation, as amended and our By-Laws, each of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this exhibit is a part. We encourage you to read our Certificate of Incorporation, our By-Laws and the applicable provisions of New York Business Corporation Law for additional information..

Our authorized capital stock currently consists of 600,000,000 shares of common stock, par value $6.50 per share. ____,____,____ shares of our common stock were issued and outstanding as of February ___, 2020. Our common stock is listed on the New York Stock Exchange. Computershare Trust Company, N.A., P.O. Box 43081, Providence, Rhode Island 02940-3081, is the transfer agent and registrar for our common stock.

Dividend Rights

The holders of our common stock are entitled to receive the dividends declared by our board of directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances.

Voting Rights

The holders of our common stock are entitled to one vote for each share of common stock held.

Rights Upon Liquidation

If we are liquidated, holders of our common stock will be entitled to receive pro rata all assets available for distribution to our shareholders after payment of our liabilities, including liquidation expenses.

Pre-emptive Rights

The holders of our common stock, whether heretofore or hereafter issued, have no preemptive rights with respect to (1) any shares of the corporation of any class or series, or (2) any other security of the corporation convertible into or carrying rights or options to purchase such shares.

Restrictions on Dealing with Existing Shareholders

We are subject to Section 513 of New York's Business Corporation Law, which provides that no domestic corporation may purchase or agree to purchase more than 10% of its stock from a shareholder who has held the shares for less than two years at any price that is higher than the market price unless the transaction is approved by both the corporation's board of directors and a majority of the votes of all outstanding shares entitled to vote thereon at a meeting of shareholders, unless the Certificate of Incorporation requires a greater percentage of the votes of the outstanding shares to approve or the corporation offers to purchase shares from all the holders on the same terms. Our Certificate of Incorporation does not currently provide for a higher percentage.

Description of Equity Units

In this Description of the Equity Units, "AEP," "we"," "us," "our" and the "Company" refer only to American Electric Power Company, Inc. and any successor obligor, and not to any of its subsidiaries.

The following is a summary of some of the terms of the Equity Units. This summary, together with the summaries of the terms of the purchase contracts, the purchase contract and pledge agreement and the Notes set forth under the captions "Description of the Purchase Contracts," "Certain Provisions of the Purchase Contract and Pledge Agreement" and "Description of the Junior Subordinated Debentures" in this prospectus supplement, contain a description of the material terms of the Equity Units, but are only summaries and are not complete. This summary is subject to and is qualified by reference to all the provisions of the purchase contract and pledge agreement, the subordinated indenture (as defined under "Description of the Junior Subordinated Debentures- Ranking"), the supplemental indenture (as defined under "Description of the Junior Subordinated Debentures-Ranking"), the Notes and the form of remarketing agreement, which has been attached as an exhibit to the purchase contract and pledge agreement, including the definitions of certain terms used therein, forms of which have been or will be filed and incorporated by reference as exhibits to the registration statement of which this prospectus supplement and the accompanying base prospectus form a part.

General

We will issue the Equity Units under the purchase contract and pledge agreement among us and The Bank of New York Mellon Trust Company, N.A., as purchase contract agent (the "purchase contract agent"), collateral agent (the "collateral agent"), custodial agent (the "custodial agent") and securities intermediary. The Equity Units may be either Corporate Units or Treasury Units. The Equity Units will initially consist of 14,000,000 Corporate Units (or 16,100,000 Corporate Units if the underwriters exercise their option to purchase additional Corporate Units in full), each with a stated amount of $50.00.

Each Corporate Unit offered will consist of:

- a purchase contract under which
    - the holder will agree to purchase from us, and we will agree to sell to the holder, on March 15, 2022 (or if such day is not a business day, the following business day), which we refer to as the "purchase contract settlement date," or earlier upon early settlement, for $50.00, a number of shares of our common stock equal to the applicable settlement rate described under "Description of the Purchase Contracts-Purchase of Common Stock," "Description of the Purchase Contracts-Early Settlement" or "Description of the Purchase Contracts-Early Settlement Upon a Fundamental Change," as the case may be, plus, in the case of an early settlement upon a fundamental change, the number of make-whole shares; and
    - we will pay the holder quarterly contract adjustment payments at the rate of 2.725% per year on the stated amount of $50.00, or $1.3625 per year, subject to our right to defer

such contract adjustment payments as described under "Description of the Purchase Contracts-Contract Adjustment Payments," and

either:

- a 1/20 undivided beneficial ownership interest in a $1,000 principal amount 3.40% junior subordinated debenture due 2024 issued by us, and under which we will pay to the holder 1/20 of the interest payment on a $1,000 principal amount Note at the initial rate of 3.40%, or $34.00 per year per $1,000 principal amount of Notes, subject to our right to defer such interest payments as described under "Description of the Junior Subordinated Debentures-Option to Defer Interest Payments;" or

- following a successful optional remarketing, the applicable ownership interest in a portfolio of U.S. Treasury securities, which we refer to as the "Treasury portfolio."

"Applicable ownership interest" means, with respect to the Treasury portfolio,

(1) a 1/20 undivided beneficial ownership interest in $1,000 face amount of U.S. Treasury securities (or principal or interest strips thereof) included in the Treasury portfolio that mature on or prior to the purchase contract settlement date; and

(2) for the scheduled interest payment occurring on the purchase contract settlement date, a 0.0425% undivided beneficial ownership interest in $1,000 face amount of U.S. Treasury securities (or principal or interest strips thereof) that mature on or prior to the purchase contract settlement date.

If U.S. Treasury securities (or principal or interest strips thereof) that are to be included in the Treasury portfolio in connection with a successful optional remarketing have a yield that is less than zero, the Treasury portfolio will consist of an amount in cash equal to the aggregate principal amount at maturity of the U.S. Treasury securities described in clauses (1) and (2) above. If the provisions set forth in this paragraph apply, references to "Treasury security" and "U.S. Treasury securities (or principal or interest strips thereof)" in connection with the Treasury portfolio will, thereafter, be deemed to be references to such amount of cash.

So long as the Equity Units are in the form of Corporate Units, the related undivided beneficial ownership interest in the Note or the applicable ownership interest in the Treasury portfolio described in clause (1) of the definition of "applicable ownership interest" above (or $50.00 in cash, if the immediately preceding paragraph applies), as the case may be, will be pledged to us through the collateral agent to secure the holders' obligations to purchase our common stock under the related purchase contracts.

Creating Treasury Units by Substituting a Treasury Security for a Note

Each holder of 20 Corporate Units may create, at any time other than after a successful remarketing or during a blackout period (as defined below), 20 Treasury Units by substituting for a Note a zero-coupon U.S. Treasury security (for example, CUSIP No. 912820ZW0) with a principal amount at maturity equal to $1,000 and maturing on February 15, 2022, which we refer to as a "Treasury security." This substitution would create 20 Treasury Units and the Note would be released from the pledge under the purchase contract and pledge agreement and delivered to the holder and would be tradable and transferable separately from the Treasury Units. Because Treasury securities and Notes are issued in integral multiples of $1,000, holders of Corporate Units may make the substitution only in integral multiples of 20 Corporate Units. After a successful remarketing, holders may not create Treasury Units from Corporate Units or recreate Corporate Units from Treasury Units.

Each Treasury Unit will consist of:

- a purchase contract under which
  - the holder will agree to purchase from us, and we will agree to sell to the holder, on the purchase contract settlement date, or earlier upon early settlement, for $50.00, a number of shares of our common stock equal to the applicable settlement rate, plus, in the case of an early settlement upon a fundamental change, the number of make-whole shares; and
  - we will pay the holder quarterly contract adjustment payments at the rate of 2.725% per year on the stated amount of $50.00, or $1.3625 per year, subject to our right to defer the contract adjustment payments; and
- a 1/20 undivided beneficial ownership interest in a Treasury security.

The term "blackout period" means the period (1) if we elect to conduct an optional remarketing, from 4:00 p.m., New York City time, on the second business day (as defined below) immediately preceding the first day of the optional remarking period until the settlement date of such optional remarketing or the date we announce that such remarketing was unsuccessful and (2) after 4:00 p.m., New York City time, on the second business day immediately preceding the first day of the final remarketing period.

The term "business day" means any day that is not a Saturday or Sunday or a day on which banking institutions in The City of New York are authorized or required by law or executive order to close.

The Treasury Unit holder's beneficial ownership interest in the Treasury security will be pledged to us through the collateral agent to secure the holder's obligation to purchase our common stock under the related purchase contracts.

To create 20 Treasury Units, a holder is required to:

- deposit with the collateral agent a Treasury security that has a principal amount at maturity of $1,000, which must be purchased in the open market at the expense of the Corporate Unit holder, unless otherwise owned by the holder; and
- transfer to the purchase contract agent 20 Corporate Units, accompanied by a notice stating that the holder of the Corporate Units has deposited a Treasury security with the collateral agent, and requesting that the purchase contract agent instruct the collateral agent to release the related Note.

Upon receiving instructions from the purchase contract agent and receipt of the Treasury security, the collateral agent will release the related Note from the pledge and deliver it to the purchase contract agent on behalf of the holder, free and clear of our security interest. The purchase contract agent then will:

- cancel the 20 Corporate Units;
- transfer the related Note to the holder; and
- deliver 20 Treasury Units to the holder.

The Treasury security will be substituted for the Note and will be pledged to us through the collateral agent to secure the holder's obligation to purchase shares of our common stock under the related purchase contracts. The Note thereafter will trade and be transferable separately from the Treasury Units.

Holders who create Treasury Units will be responsible for any taxes, governmental charges or other fees or expenses (including, without limitation, fees and expenses payable to the collateral agent) attributable to such collateral substitution. See "Certain Provisions of the Purchase Contract and Pledge Agreement-Miscellaneous."

Recreating Corporate Units

Each holder of 20 Treasury Units will have the right, at any time, other than during a blackout period or after a successful remarketing, to substitute for the related Treasury security held by the collateral agent a Note having a principal amount equal to $1,000. This substitution would recreate 20 Corporate Units and the applicable Treasury security would be released from the pledge under the purchase contract and pledge agreement and delivered to the holder and would be tradable and transferable separately from the Corporate Units. Because Treasury securities and Notes are issued in integral multiples of $1,000, holders of Treasury Units may make this substitution only in integral multiples of 20 Treasury Units. After a successful remarketing, holders may not recreate Corporate Units from Treasury Units.

To recreate 20 Corporate Units, a holder is required to:

- deposit with the collateral agent a Note having a principal amount of $1,000, which must be purchased in the open market at the expense of the Treasury Unit holder, unless otherwise owned by the holder; and

- transfer to the purchase contract agent 20 Treasury Units, accompanied by a notice stating that the holder of the Treasury Units has deposited a Note having a principal amount of $1,000 with the collateral agent and requesting that the purchase contract agent instruct the collateral agent to release the related Treasury security.

Upon receiving instructions from the purchase contract agent and receipt of the Note having a principal amount of $1,000, the collateral agent will promptly release the related Treasury security from the pledge and promptly instruct the securities intermediary to transfer such Treasury security to the purchase contract agent for distribution to the holder, free and clear of our security interest. The purchase contract agent then will:

- cancel the 20 Treasury Units;

- transfer the related Treasury security to the holder; and

- deliver 20 Corporate Units to the holder.

The $1,000 principal amount Note will be substituted for the Treasury security and will be pledged to us through the collateral agent to secure the holder's obligation to purchase shares of our common stock under the related purchase contracts. The Treasury security thereafter will trade and be transferable separately from the Corporate Units.

Holders who recreate Corporate Units will be responsible for any taxes, governmental charges or other fees or expenses (including, without limitation, fees and expenses payable to the collateral agent) attributable to the collateral substitution. See “Certain Provisions of the Purchase Contract and Pledge Agreement-Miscellaneous.”

Payments on the Equity Units

Holders of Corporate Units and Treasury Units will receive quarterly contract adjustment payments payable by us at the rate of 2.725% per year on the stated amount of $50.00 per Equity Unit. We will make all contract adjustment payments on the Corporate Units and the Treasury Units quarterly in arrears on March 15, June 15, September 15 and December 15 of each year (except that if any such date is not a business day, contract adjustment payments will be payable on the following business day, without adjustment), commencing June 15, 2019. Unless the purchase contracts have been terminated (as described under “Description of the Purchase Contracts-Termination” below), we will make such contract adjustment payments until the earliest of the purchase contract settlement date, the fundamental change early settlement date (in the case of a fundamental change early settlement, as described under “Description of the Purchase Contracts-Early Settlement Upon a Fundamental Change” below) and the most recent contract adjustment payment date on or before any other early settlement with respect to the related purchase contracts (in the case of an early settlement as described under “Description of the Purchase Contracts-Early Settlement” below). If the purchase contracts have been terminated, our obligation to pay the contract adjustment payments, including any accrued and unpaid contract adjustment payments and deferred contract adjustment payments (including compounded contract adjustment payments thereon), will cease. In addition, holders of Corporate Units will receive quarterly cash distributions consisting of their pro rata share of interest payments on the Notes (or distributions on the applicable ownership interest in the Treasury portfolio, as applicable), equivalent to the rate of 3.40% per year. There will be no interest payments in respect of the Treasury securities that are a component of the Treasury Units, but to the extent that such holders of Treasury Units continue to hold the Notes that were delivered to them when they created the Treasury Units, such holders will continue to receive the scheduled interest payments on their separate Notes for as long as they hold the Notes.

We have the right to defer payment of quarterly contract adjustment payments and of interest on the Notes as described under “Description of the Purchase Contracts-Contract Adjustment Payments” and “Description of the Junior Subordinated Debentures-Option to Defer Interest Payments,” respectively.

Listing

We intend to apply to list the Corporate Units on the New York Stock Exchange and expect trading to commence within 30 days of the initial issuance of the Corporate Units under the symbol “AEPPRB.” Except in connection with early settlement, fundamental change early settlement, a termination event or settlement on the purchase contract settlement date with separate cash, unless and until substitution has been made as described in “-Creating Treasury Units by Substituting a Treasury Security for a Note” or “-Recreating Corporate Units,” neither the Note or applicable ownership interest in the Treasury portfolio component of a Corporate Unit nor the Treasury security component of a Treasury Unit will trade separately from Corporate Units or Treasury Units. The Note or applicable ownership interest in the Treasury portfolio component will trade as a unit with the purchase contract component of the Corporate Units, and the Treasury security component will trade as a unit with the purchase contract component of the Treasury Units. In addition, if Treasury Units or Notes are separately traded to a sufficient extent that the applicable exchange listing requirements are met, we may endeavor to cause the Treasury Units or Notes to be listed on the exchange on which the Corporate Units are then listed, including, if applicable, the New York Stock Exchange. However, there can be no assurance that we will list the Treasury Units or the Notes.

Ranking

The Notes, which are included in the Equity Units, will be our junior subordinated obligations, subordinated to our existing and future Senior Indebtedness (as defined under "Description of the Junior Subordinated Debentures-Subordination"). The Notes will be issued under our subordinated indenture and the supplemental indenture (each defined under "Description of the Junior Subordinated Debentures-Ranking").

In addition, our obligations with respect to contract adjustment payments will be subordinate in right of payment to our existing and future Senior Indebtedness (as defined under "Description of the Junior Subordinated Debentures-Subordination").

The Notes and our obligations with respect to contract adjustments payments will be structurally subordinated to existing or future preferred stock and indebtedness, guarantees and other liabilities, including trade payables, of our subsidiaries.

Our subsidiaries are separate and distinct legal entities from us. Our subsidiaries have no obligation to pay any amounts due on the Notes or the purchase contracts or to provide us with funds to meet our respective payment obligations on the Notes or purchase contracts. Any payment of dividends, loans or advances by our subsidiaries to us could be subject to statutory or contractual restrictions and will be contingent upon the subsidiaries' earnings and business considerations. Our right to receive any assets of any of our subsidiaries upon their bankruptcy, liquidation or similar reorganization, and therefore the right of the holders of the Notes or purchase contracts to participate in those assets, will be structurally subordinated to the claims of that subsidiary's creditors, including trade creditors. Even if we are a creditor of any of our subsidiaries, our rights as a creditor would be subordinate to any security interest in the assets of our subsidiaries and any indebtedness of our subsidiaries senior to that held by us.

Voting and Certain Other Rights

Prior to the delivery of shares of common stock under each purchase contract, such purchase contract shall not entitle the holder of the Corporate Units or Treasury Units to any rights of a holder of shares of our common stock, including, without limitation, the right to vote or receive any dividends or other payments or distributions or to consent to or to receive notice as a shareholder or other rights in respect of our common stock.

Agreed Tax Treatment

Each beneficial owner of an Equity Unit, by acceptance of a beneficial interest therein, will be deemed to have agreed for U.S. federal, state and local income tax purposes (unless otherwise required by any taxing authority) (1) to treat itself as the owner, separately, of each of the applicable purchase contract and the related Note or the applicable ownership interests in the Treasury portfolio or Treasury security, as the case may be, (2) to treat the Note as indebtedness that is a "contingent payment debt instrument" (as that term is used in U.S. Treasury regulations section 1.1275-4), (3) to be bound by our determination of the comparable yield and payment schedule with respect to the Note, and (4) to allocate, as of the issue date, 100.00% of the purchase price paid for the Corporate Units to its ownership interest in the Note and 0.00% to each purchase contract, which will establish its initial tax basis in each purchase contract as $0.00 and the beneficial owner's initial tax basis in each Note as $50.00. This position will beinding on each beneficial owner of each Equity Unit, but not on the IRS. See "Certain United States Federal Income and Estate Tax Consequences."

Repurchase of the Equity Units

We may purchase from time to time any of the Equity Units that are then outstanding by tender, in the open market, by private agreement or otherwise, subject to compliance with applicable law, *provided* that any of the Equity Units repurchased by us will be cancelled.

DESCRIPTION OF THE PURCHASE CONTRACTS

The following is a summary of some of the terms of the purchase contracts. The purchase contracts will be issued pursuant to the purchase contract and pledge agreement among us, the purchase contract agent, the collateral agent, the custodial agent and the securities intermediary. The summaries of the purchase contracts and the purchase contract and pledge agreement contain a description of the material terms of the contracts but are only summaries and are not complete. This summary is subject to and is qualified by reference to all the provisions of the purchase contract and pledge agreement, the subordinated indenture (as defined under "Description of the Junior Subordinated Debentures-Ranking"), the supplemental indenture (as defined under "Description of the Junior Subordinated Debentures-Ranking"), the Notes and the form of remarketing agreement, including the definitions of certain terms used therein, forms of which have been or will be filed and incorporated by reference as an exhibit to the registration statement of which this prospectus supplement and the accompanying base prospectus form a part.

Purchase of Common Stock

Each purchase contract that is a component of a Corporate Unit or a Treasury Unit will obligate its holder to purchase, and us to issue and deliver, on March 15, 2022 (or if such day is not a business day, the following business day) (the "purchase contract settlement date"), for $50.00 in cash a number of shares of our common stock equal to the settlement rate (together with cash, if applicable, in lieu of any fractional shares of common stock in the manner described below), in each case, unless the purchase contract terminates prior to that date or is settled early at the holder's option. The number of shares of our common stock issuable upon settlement of each purchase contract on the purchase contract settlement date (which we refer to as the "settlement rate") will be determined as follows, subject to adjustment as described under "-Anti-dilution Adjustments" below:

(1) If the applicable market value of our common stock is equal to or greater than the "threshold appreciation price" of $99.5818, the settlement rate will be 0.5021 shares of our common stock (we refer to this settlement rate as the "minimum settlement rate").

Accordingly, if the market price for our common stock increases between the date of this prospectus supplement and the period during which the applicable market value is measured and the applicable market value is greater than the threshold appreciation price, the aggregate market value of the shares of common stock issued upon settlement of each purchase contract will be higher than the stated amount, assuming that the market price of the common stock on the purchase contract settlement date is the same as the applicable market value of the common stock. If the applicable market value is the same as the threshold appreciation price, the aggregate market value of the shares issued upon settlement will be equal to the stated amount, assuming that the market price of the common stock on the purchase contract settlement date is the same as the applicable market value of the common stock.

(2) If the applicable market value of our common stock is less than the threshold appreciation price but greater than the "reference price" of $82.98, which will be the closing price of our common stock on the New York Stock Exchange on the date the Equity Units are priced in

this offering, the settlement rate will be a number of shares of our common stock equal to $50.00 divided by the applicable market value, rounded to the nearest ten thousandth of a share.

Accordingly, if the market price for the common stock increases between the date of this prospectus supplement and the period during which the applicable market value is measured, but the market price does not exceed the threshold appreciation price, the aggregate market value of the shares of common stock issued upon settlement of each purchase contract will be equal to the stated amount, assuming that the market price of the common stock on the purchase contract settlement date is the same as the applicable market value of the common stock.

(3) If the applicable market value of our common stock is less than or equal to the reference price of $82.98, the settlement rate will be 0.6026 shares of our common stock, which is equal to the stated amount divided by the reference price (we refer to this settlement rate as the "maximum settlement rate").

Accordingly, if the market price for the common stock decreases between the date of this prospectus supplement and the period during which the applicable market value is measured and the market price is less than the reference price, the aggregate market value of the shares of common stock issued upon settlement of each purchase contract will be less than the stated amount, assuming that the market price on the purchase contract settlement date is the same as the applicable market value of the common stock. If the market price of the common stock is the same as the reference price, the aggregate market value of the shares will be equal to the stated amount, assuming that the market price of the common stock on the purchase contract settlement date is the same as the applicable market value of the common stock.

The threshold appreciation price is equal to $50.00 divided by the minimum settlement rate (such quotient rounded to the nearest $0.0001), which is $99.5818.

If you elect to settle your purchase contract early in the manner described under "-Early Settlement," the number of shares of our common stock issuable upon settlement of such purchase contract will be 0.5021, the minimum settlement rate, subject to adjustment as described under "-Anti-dilution Adjustments." If you elect to settle your purchase contract early upon a fundamental change, the number of shares of our common stock issuable upon settlement will be determined as described under "-Early Settlement Upon a Fundamental Change." We refer to the minimum settlement rate and the maximum settlement rate as the "fixed settlement rates."

The "applicable market value" means the average volume-weighted average price, or VWAP, of our common stock on each trading day during the 20 consecutive scheduled trading day period ending on the third scheduled trading day immediately preceding the purchase contract settlement date (the "market value averaging period"). The "VWAP" of our common stock means, for the relevant trading day, the per share VWAP on the principal exchange or quotation system on which our common stock is listed or admitted for trading as displayed under the heading Bloomberg VWAP on Bloomberg page AEP <EQUITY> AQR (or its equivalent successor if that page is not available) in respect of the period from the scheduled open of trading on the relevant trading day until the scheduled close of trading on the relevant trading day (or if such VWAP is unavailable, the market price of one share of our common stock on such trading day determined, using a volume-weighted average method, by a nationally recognized independent investment banking firm retained for this purpose by us).

A "trading day" means, for purposes of determining a VWAP or closing price, a day (1) on which the principal exchange or quotation system on which our common stock is listed or admitted for trading is scheduled to be open for business and (2) on which there has not occurred or does not exist a market disruption event.

A "market disruption event" means any of the following events:

- any suspension of, or limitation imposed on, trading by the principal exchange or quotation system on which our common stock is listed or admitted for trading during the one-hour period prior to the close of trading for the regular trading session on such exchange or quotation system (or for purposes of determining a VWAP any period or periods prior to 1:00 p.m. New York City time aggregating one half hour or longer) and whether by reason of movements in price exceeding limits permitted by the relevant exchange or quotation system or otherwise relating to our common stock or in futures or option contracts relating to our common stock on the relevant exchange or quotation system; or

- any event (other than a failure to open or, except for purposes of determining a VWAP, a closure as described below) that disrupts or impairs the ability of market participants during the one-hour period prior to the close of trading for the regular trading session on the principal exchange or quotation system on which our common stock is listed or admitted for trading (or for purposes of determining a VWAP any period or periods prior to 1:00 p.m. New York City time aggregating one half hour or longer) in general to effect transactions in, or obtain market values for, our common stock on the relevant exchange or quotation system or futures or options contracts relating to our common stock on any relevant exchange or quotation system; or

- the failure to open of the principal exchange or quotation system on which futures or options contracts relating to our common stock are traded or, except for purposes of determining a VWAP, the closure of such exchange or quotation system prior to its respective scheduled closing time for the regular trading session on such day (without regard to after hours or other trading outside the regular trading session hours) unless such earlier closing time is announced by such exchange or quotation system at least one hour prior to the earlier of the actual closing time for the regular trading session on such day and the submission deadline for orders to be entered into such exchange or quotation system for execution at the actual closing time on such day.

If a market disruption event occurs on any scheduled trading day during the market value averaging period, we will notify investors on the calendar day on which such event occurs.

If 20 trading days for our common stock have not occurred during the market value averaging period, all remaining trading days will be deemed to occur on the third scheduled trading day immediately prior to the purchase contract settlement date and the VWAP of our common stock for each of the remaining trading days will be the VWAP of our common stock on that third scheduled trading day or, if such day is not a trading day, the closing price as of such day.

The "closing price" per share of our common stock means, on any date of determination, the closing sale price or, if no closing sale price is reported, the last reported sale price of our common stock on the principal U.S. securities exchange on which our common stock is listed, or if our common stock is not so listed on a U.S. securities exchange, the average of the last quoted bid and ask prices for our common stock in the over-the-counter market as reported by OTC Markets Group Inc. or similar organization, or, if those bid and ask prices are not available, the market value of our common stock on that date as determined by a nationally recognized independent investment banking firm retained by us for this purpose.

We will not issue any fractional shares of our common stock upon settlement of a purchase contract. Instead of a fractional share, the holder will receive an amount of cash equal to the percentage of a whole share represented by such fractional share multiplied by the closing price of our common stock on the trading day immediately preceding the purchase contract settlement date (or the trading day immediately preceding the relevant settlement date, in the case of early settlement). If, however, a holder surrenders for settlement at one time more than one purchase contract, then the number of shares of our common stock issuable pursuant to such purchase contracts will be computed based upon the aggregate number of purchase contracts surrendered.

Unless:

- a holder has settled early the related purchase contracts by delivery of cash to the purchase contract agent in the manner described under "-Early Settlement" or "-Early Settlement Upon a Fundamental Change;"

- a holder of Corporate Units has settled the related purchase contracts with separate cash in the manner described under "-Notice to Settle with Cash;" or

- an event described under "-Termination" has occurred;

then, on the purchase contract settlement date,

- in the case of Corporate Units where there has not been a successful optional or final remarketing, the holder will be deemed to have exercised its put right as described under "-Remarketing" (unless it shall have elected not to exercise such put right by delivering cash as described thereunder) and to have elected to apply the proceeds of the put price to satisfy in full the holder's obligation to purchase our common stock under the related purchase contracts;

- in the case of Corporate Units where the Treasury portfolio or cash has replaced the Notes as a component of the Corporate Units following a successful optional remarketing, the portion of the proceeds of the applicable ownership interests in the Treasury portfolio when paid at maturity or an amount of cash equal to the stated amount of $50.00 per Corporate Unit will be applied to satisfy in full the holder's obligation to purchase common stock under the related purchase contracts and any excess proceeds will be delivered to the purchase contract agent for the benefit of the holders of Corporate Units;

- in the case of Corporate Units where the Notes have been successfully remarketed during the final remarketing period, the portion of the remarketing proceeds sufficient to satisfy the holder's obligation to purchase our common stock under the related purchase contracts will be applied to satisfy in full the holder's obligation to purchase common stock under the related purchase contracts and any excess proceeds will be delivered to the purchase contract agent for the benefit of the holders of Corporate Units; and

- in the case of Treasury Units, the proceeds of the related Treasury securities, when paid at maturity, will be applied to satisfy in full the holder's obligation to purchase our common stock under the related purchase contracts and any excess proceeds will be delivered to the purchase contract agent for the benefit of the holders of Treasury Units.

The common stock will then be issued and delivered to the holder or the holder's designee on the purchase contract settlement date. We will pay all stock transfer and similar taxes attributable to the initial issuance and delivery of the shares of our common stock pursuant to the purchase contracts, unless any such tax is due because the holder requests such shares to be issued in a name other than such holder's name.

Prior to the settlement of a purchase contract, the shares of our common stock underlying each purchase contract will not be outstanding, and the holder of the purchase contract will not have any voting rights, rights to dividends or other distributions or other rights of a holder of our common stock by virtue of holding such purchase contract.

By purchasing a Corporate Unit or a Treasury Unit, a holder will be deemed to have, among other things:

- irrevocably appointed the purchase contract agent as its attorney-in-fact to enter into and perform the related purchase contract and the purchase contract and pledge agreement in the name of and on behalf of such holder;

- agreed to be bound by the terms and provisions of the Corporate Units or Treasury Units, as applicable, including, but not limited to, the terms of the related purchase contract and the purchase contract and pledge agreement, for so long as the holder remains a holder of Corporate Units or Treasury Units;

- consented to and agreed to be bound by the pledge of such holder's right, title and interest in and to its undivided beneficial ownership interest in Notes, the portion of the Treasury portfolio (or cash) described in the first clause of the definition of "applicable ownership interest," or the Treasury securities, as applicable, and the delivery of such collateral by the purchase contract agent to the collateral agent; and

- agreed to the satisfaction of the holder's obligations under the purchase contracts with the proceeds of the pledged undivided beneficial ownership in the Notes, Treasury portfolio (or cash), Treasury securities or put price, as applicable, in the manner described above.

Remarketing

We have agreed to enter into a remarketing agreement with one or more remarketing agents, the "remarketing agent," no later than 20 days prior to the first day of the final remarketing period or, if we elect to conduct an optional remarketing, no later than 20 days prior to the optional remarketing period.

During a blackout period that relates to each remarketing period:

- you may not settle a purchase contract early;

- you may not create Treasury Units; and

- you may not recreate Corporate Units from Treasury Units.

We refer to each of an "optional remarketing" and a "final remarketing" as a "remarketing." In a remarketing, the Notes that are a part of Corporate Units (except, in the case of a final remarketing, where the holder has elected to settle the purchase contract through payment of separate cash) and any separate Notes whose holders have elected to participate in the remarketing, as described under "Description of the Junior Subordinated Debentures-Remarketing of the Notes That Are Not Included in Corporate Units," will be remarketed.

In consultation with the remarketing agent and without the consent of any holders of Notes, we may elect (but shall not be required to elect) to remarket the Notes as fixed-rate Notes or floating-rate Notes and, in the case of floating-rate Notes, provide that the interest on the Notes will be equal to an index rate determined by the Company plus a spread determined by the remarketing agent, in consultation with the Company, in which case interest on the Notes may be calculated on the basis of a 365 day year and the actual number of days elapsed (or such other basis as is customarily used for floating-rate Notes bearing interest at a rate based on such index rate).

All such modifications shall take effect only if the remarketing is successful, without the consent of the holders, upon the earlier of the optional remarketing settlement date and the purchase contract settlement date, and will apply to all of the Notes whether or not included in the remarketing. See “Description of the Junior Subordinated Debentures-Remarketing.” If we conduct an optional remarketing that is not successful, we may change the elections described above prior to the final remarketing period.

In order to remarket the Notes, the remarketing agent, in consultation with us, may reset the interest rate on the Notes (either upward or downward), or if the Notes are remarketed as floating-rate Notes, determine the interest rate spread applicable to the Notes, in order to produce the required price in the remarketing, as discussed under “-Optional Remarketing” and “-Final Remarketing” below. The interest deferral provisions of the Notes will not apply after a successful remarketing.

We will use commercially reasonable efforts to ensure that, if required by applicable law, a registration statement, including a prospectus, with regard to the full amount of the Notes to be remarketed will be effective under the securities laws in a form that may be used by the remarketing agent in connection with the remarketing (unless a registration statement is not required under the applicable laws and regulations that are in effect at that time or unless we conduct any remarketing in accordance with an exemption under the securities laws).

We will separately pay a fee to the remarketing agent for its services as remarketing agent. Holders whose Notes are remarketed will not be responsible for the payment of any remarketing fee in connection with the remarketing.

Optional Remarketing

Unless a termination event has occurred, we may elect, at our option, to engage the remarketing agent pursuant to the terms of the remarketing agreement, to remarket the Notes over a period selected by us that begins on or after December 13, 2021 (the third business day immediately preceding the last interest payment date prior to the purchase contract settlement date) and ends any time on or before February 24, 2022 (the eighth calendar day immediately preceding the first day of the final remarketing period). We refer to this period as the “optional remarketing period,” a remarketing that occurs during the optional remarketing period as an “optional remarketing” and the date the Notes are priced in an optional remarketing as the “optional remarketing date.” In any optional remarketing, the aggregate principal amount of the Notes that are a part of Corporate Units and any separate Notes whose holders have elected to participate in the optional remarketing, as described under “Description of the Junior Subordinated Debentures-Remarketing of the Notes That Are Not Included in Corporate Units,” will be remarketed. If we elect to conduct an optional remarketing, the remarketing agent will use its commercially reasonable efforts to obtain a price for the Notes that results in proceeds of at least 100% of the aggregate of the Treasury portfolio purchase price (as defined below) and the separate Notes purchase price (as defined below). To obtain that price, the remarketing agent may, in consultation with us, reset the interest rate on the Notes remarketed as fixed-rate Notes, or determine the interest rate spread for the Notes remarketed as floating-rate Notes, as described under “Description of the Junior Subordinated Debentures-Interest Rate Reset.” We will request that the depository notify its participants holding Corporate Units, Treasury Units and separate Notes of our election to conduct an optional remarketing no later than five business days prior to the date we begin the optional remarketing.

Notwithstanding anything in this prospectus supplement to the contrary, we may not elect to conduct an optional remarketing if we are then deferring interest on the Notes. See "Description of the Junior Subordinated Debentures-Option to Defer Interest Payments."

An optional remarketing on any remarketing date will be considered successful if the remarketing agent is able to remarket the Notes for a price of at least 100% of the Treasury portfolio purchase price and the separate Notes purchase price.

Following a successful optional remarketing of the Notes, on the optional remarketing settlement date (as defined below), the portion of the remarketing proceeds equal to the Treasury portfolio purchase price will, except as described below, be used to purchase the Treasury portfolio and the remaining proceeds attributable to the Notes underlying the Corporate Units will be remitted to the purchase contract agent for distribution pro rata to the holders of such Corporate Units. The portion of the proceeds attributable to the separate Notes sold in the remarketing will be remitted to the custodial agent for distribution on the optional remarketing settlement date pro rata to the holders of such separate Notes.

If we elect to conduct an optional remarketing and the remarketing is successful:

- settlement with respect to the remarketed Notes will occur on the second business day following the optional remarketing date, unless the remarketed Notes are priced after 4:30 p.m. New York time on the optional remarketing date, in which case settlement will occur on the third business day following the optional remarketing date (we refer to such settlement date as the "optional remarketing settlement date");
- the interest rate on the Notes will be reset, or, if we remarketed the Notes as floating-rate Notes, the interest rate spread will be determined, by the remarketing agent in consultation with us on the optional remarketing date and will become effective on the optional remarketing settlement date, if applicable;
- except in the case when the Notes are remarketed as floating-rate Notes, interest on the Notes will be payable semi-annually;
- the interest deferral provisions will cease to apply to the Notes;
- the other modifications to the terms of the Notes, as described under "-Remarketing," will become effective;
- after the optional remarketing settlement date, your Corporate Units will consist of a purchase contract and the applicable ownership interest in the Treasury portfolio (or cash), as described herein; and
- you may no longer create Treasury Units or recreate Corporate Units from Treasury Units.

If we do not elect to conduct an optional remarketing during the optional remarketing period or no optional remarketing succeeds for any reason, the Notes will continue to be a component of the Corporate Units or will continue to be held separately and the remarketing agent will use its commercially reasonable efforts to remarket the Notes during the final remarketing period.

For the purposes of a successful optional remarketing, "Treasury portfolio purchase price" means the lowest aggregate ask-side price quoted by a primary U.S. government securities dealer in New York City to the quotation agent selected by us between 9:00 a.m. and 4:00 p.m., New York City time, on the optional remarketing date for the purchase of the Treasury portfolio for settlement on the optional remarketing settlement date; *provided* that if the Treasury portfolio consists of cash, “Treasury portfolio purchase price” means the amount of such cash.

Following a successful optional remarketing, the collateral agent will purchase, at the Treasury portfolio purchase price, a Treasury portfolio consisting of:

- U.S. Treasury securities (or principal or interest strips thereof) that mature on or prior to the purchase contract settlement date in an aggregate amount at maturity equal to the principal amount of the Notes underlying the undivided beneficial ownership interests in Notes included in the Corporate Units on the optional remarketing date; and

- U.S. Treasury securities (or principal or interest strips thereof) that mature on or prior to the purchase contract settlement date in an aggregate amount equal to the aggregate interest payment (assuming no reset of the interest rate) that would have been paid to the holders of the Corporate Units on the purchase contract settlement date on the principal amount of the Notes underlying the undivided beneficial ownership interests in Notes included in the Corporate Units on the optional remarketing date.

If U.S. Treasury securities (or principal or interest strips thereof) that are to be included in the Treasury portfolio in connection with a successful optional remarketing have a yield that is less than zero, the Treasury portfolio will consist of an amount in cash equal to the aggregate principal amount at maturity of the U.S. Treasury securities described in the bullet points above. If the provisions set forth in this paragraph apply, references in this prospectus supplement to a “Treasury security” and “U.S. Treasury securities (or principal or interest strips thereof)” in connection with the Treasury portfolio will, thereafter, be deemed to be references to such amount in cash.

The applicable ownership interests in the Treasury portfolio will be substituted for the undivided beneficial ownership interests in Notes that are components of the Corporate Units and the portion of the Treasury portfolio described in the first bullet will be pledged to us through the collateral agent to secure the Corporate Unit holders’ obligation under the purchase contracts. On the purchase contract settlement date, for each Corporate Unit, $50.00 of the proceeds from the Treasury portfolio will automatically be applied to satisfy the Corporate Unit holder’s obligation to purchase common stock under the purchase contract. In addition, proceeds from the portion of the Treasury portfolio described in the second bullet, which will equal the interest payment (without reference to the reset of the interest rate) that would have been paid on the Notes that were components of the Corporate Units at the time of remarketing, will be paid on the purchase contract settlement date to the holders of the Corporate Units.

If we elect to remarket the Notes during the optional remarketing period and a successful remarketing has not occurred on or prior to February 24, 2022 (the last day of the optional remarketing period), we will cause a notice of the failed remarketing to be published no later than 9:00 a.m., New York City time, on the business day immediately following the last date of the optional remarketing period. This notice will be validly published by making a timely release to any appropriate news agency, including Bloomberg Business News and the Dow Jones News Service. We will similarly cause a notice of a successful remarketing of the Notes to be published no later than 9:00 a.m., New York City time, on the business day immediately following the date of such successful remarketing.

On each business day during any optional remarketing period, we have the right in our sole and absolute discretion to determine whether or not an optional remarketing will be attempted. At any time and from time to time during the optional remarketing period prior to the announcement of a successful optional remarketing, we have the right to postpone any optional remarketing in our sole and absolute discretion.

Final Remarketing

Unless a termination event or a successful optional remarketing has previously occurred, we will remarket the Notes during the five business day period ending on, and including, March 10, 2022 (the third business day immediately preceding the purchase contract settlement date). We refer to this period as the “final remarketing period,” the remarketing during this period as the “final remarketing” and the date the Notes are priced in the final marketing as the “final remarketing date.” In the final remarketing, the aggregate principal amount of the Notes that are a part of Corporate Units (except where the holder has elected to settle the purchase contract through payment of separate cash) and any separate Notes whose holders have elected to participate in the final remarketing will be remarketed. The remarketing agent will use its commercially reasonable efforts to obtain a price for the Notes to be remarketed that results in proceeds of at least 100% of the principal amount of all the Notes offered in the remarketing. To obtain that price, the remarketing agent, in consultation with us, may reset the interest rate on the Notes if the Notes are remarketed as fixed-rate Notes, or determine the interest rate spread on the Notes if the Notes are remarketed as floating-rate Notes, as described under “Description of the Junior Subordinated Debentures-Interest Rate Reset.” We will request that the depository notify its participants holding Corporate Units, Treasury Units and separate Notes of the final remarketing no later than seven days prior to the first day of the final remarketing period. In such notice, we will set forth the dates of the final remarketing period, applicable procedures for holders of separate Notes to participate in the final remarketing, the applicable procedures for holders of Corporate Units to create Treasury Units and for holders of Treasury Units to recreate Corporate Units, the applicable procedures for holders of Corporate Units to settle their purchase contracts early and any other applicable procedures, including the procedures that must be followed by a holder of separate Notes in the case of a failed remarketing if a holder of separate Notes wishes to exercise its right to put its Notes to us as described below and under “Description of the Junior Subordinated Debentures-Put Option upon Failed Remarketing.” We have the right to postpone the final remarketing in our sole and absolute discretion on any day prior to the last three business days of the final remarketing period.

A remarketing during the final remarketing period will be considered successful if the remarketing agent is able to remarket the Notes for a price of at least 100% of the aggregate principal amount of all the Notes offered in the remarketing.

If the final remarketing is successful:

- settlement with respect to the remarketed Notes will occur on the purchase contract settlement date;

- the interest rate of the Notes will be reset, or, if the Notes are remarketed as floating-rate Notes, the interest rate spread will be determined, by the remarketing agent in consultation with us, and will become effective on the reset effective date, which will be the purchase contract settlement date, as described under “Description of the Junior Subordinated Debentures-Interest Rate Reset” below;

- the other modifications to the terms of the Notes, as described under “-Remarketing,” will become effective; and

- the collateral agent will remit the portion of the proceeds equal to the total principal amount of the Notes underlying the Corporate Units to us to satisfy in full the Corporate Unit holders’ obligations to purchase common stock under the related purchase contracts, any excess proceeds attributable to Notes underlying Corporate Units that were remarketed will be remitted to the purchase contract agent for distribution pro rata to the holders of such Notes and proceeds from the final remarketing attributable to the separate Notes remarketed will be remitted to the custodial agent for distribution pro rata to the holders of the remarketed separate Notes.

Unless a termination event has occurred, a holder has effected an early settlement or a fundamental change early settlement, or there has been a successful optional remarketing, each Corporate Unit holder has the option at any time on or after the date we give notice of a final remarketing to notify the purchase contract agent at any time prior to 4:00 p.m., New York City time, on the second business day immediately prior to the first day of the final remarketing period of its intention to settle the related purchase contracts on the purchase contract settlement date with separate cash and to provide that cash on or prior to the business day immediately prior to the first day of the final remarketing period, as described under "-Notice to Settle with Cash." The Notes of any holder of Corporate Units who has not given this notice or failed to deliver the cash will be remarketed during the final remarketing period. In addition, holders of Notes that do not underlie Corporate Units may elect to participate in the remarketing as described under "Description of the Junior Subordinated Debentures-Remarketing of Notes That Are Not Included in Corporate Units."

If, in spite of using its commercially reasonable efforts, the remarketing agent cannot remarket the Notes during the final remarketing period at a price equal to or greater than 100% of the aggregate principal amount of the Notes offered in the remarketing, a condition precedent set forth in the remarketing agreement has not been fulfilled or a successful remarketing has not occurred for any other reason, in each case resulting in a "failed remarketing," holders of all Notes will have the right to put their Notes to us for an amount equal to the principal amount of their Notes (the "put price"). The conditions precedent in the remarketing agreement will include, but not be limited to, the timely filing with the SEC of all material related to the remarketing required to be filed by us, the truth and correctness of certain representations and warranties made by us in the remarketing agreement, the furnishing of certain officer's certificates to the remarketing agent, and the receipt by the remarketing agent of customary "comfort letters" from our auditors and opinions of counsel. A holder of Corporate Units will be deemed to have automatically exercised this put right with respect to the Notes underlying such Corporate Units unless the holder has provided a written notice to the purchase contract agent of its intention to settle the purchase contract with separate cash as described below under "-Notice to Settle with Cash" prior to 4:00 p.m., New York City time, on the second business day immediately prior to the purchase contract settlement date, and on or prior to the business day immediately preceding the purchase contract settlement date has delivered the $50.00 in cash per purchase contract. Settlement with separate cash may only be effected in integral multiples of 20 Corporate Units. If a holder of Corporate Units elects to settle with separate cash, upon receipt of the required cash payment, the related Notes underlying the Corporate Units will be released from the pledge under the purchase contract and pledge agreement and delivered promptly to the purchase contract agent for delivery to the holder. The holder of the Corporate Units will then receive the applicable number of shares of our common stock on the purchase contract settlement date. The cash received by the collateral agent upon this settlement with separate cash may be invested in permitted investments, as defined in the purchase contract and pledge agreement, and the portion of the proceeds equal to the aggregate purchase price of all purchase contracts of such holders will be paid to us on the purchase contract settlement date. Any excess funds received by the collateral agent in respect of any such permitted investments over the aggregate purchase price remitted to us in satisfaction of the obligations of the holders under the purchase contracts will be distributed to the purchase contract agent for ratable payment to the applicable holders who settled with separate cash. Unless a holder of Corporate Units has elected to settle the related purchase contracts with separate cash and delivered the separate cash on or prior to the business day immediately preceding the purchase contract settlement date, the holder will be deemed to have elected to apply the put price against the holder's obligations to pay the aggregate purchase price for the shares of our common stock to be issued under the related purchase contracts, thereby satisfying the obligations in full, and we will deliver to the holder our common stock pursuant to the related purchase contracts.

If a successful final remarketing has not occurred on or prior to March 10, 2022 (the last day of the final remarketing period), we will cause a notice of the failed remarketing of the Notes to be published no later than 9:00 a.m., New York City time, on the business day immediately following the last date of the final remarketing period. This notice will be validly published by making a timely release to any appropriate news agency, including Bloomberg Business News and the Dow Jones News Service.

Early Settlement

Subject to the conditions described below, a holder of Corporate Units or Treasury Units may settle the related purchase contracts at any time prior to 4:00 p.m., New York City time, on the second business day immediately preceding the purchase contract settlement date, other than during a blackout period in the case of Corporate Units. An early settlement may be made only in integral multiples of 20 Corporate Units or 20 Treasury Units; however, if the Treasury portfolio has replaced the Notes as a component of the Corporate Units following a successful optional remarketing, holders of Corporate Units may settle early only in integral multiples of 40,000 Corporate Units. In order to settle purchase contracts early, a holder of Equity Units must deliver to the purchase contract agent at the corporate trust office of the purchase contract agent or its agent, in each case, in the Borough of Manhattan, The City of New York (1) a completed "Election to Settle Early" form, along with the Corporate Unit or Treasury Unit certificate, if they are in certificated form and (2) a cash payment in immediately available funds in an amount equal to:

- $50.00 times the number of purchase contracts being settled; plus
- if the early settlement date occurs during the period from the close of business on any record date next preceding any contract adjustment payment date to the opening of business on such contract adjustment payment date, an amount equal to the contract adjustment payments payable on such contract adjustment payment date, unless we have elected to defer the contract adjustment payments payable on such contract adjustment payment date.

So long as you hold Equity Units as a beneficial interest in a global security certificate deposited with the depository, procedures for early settlement will also be governed by standing arrangements between the depository and the purchase contract agent.

The early settlement right is also subject to the condition that, if required under U.S. federal securities laws, we have a registration statement under the Securities Act in effect with respect to the shares of common stock and other securities, if any, deliverable upon settlement of a purchase contract. We have agreed that, if such a registration statement is required, we will use our commercially reasonable efforts to (1) have a registration statement in effect covering those shares of common stock and other securities, if any, to be delivered in respect of the purchase contracts being settled and (2) provide a prospectus in connection therewith, in each case in a form that may be used in connection with the early settlement right (it being understood that if there is a material business transaction or development that has not yet been publicly disclosed, we will not be required to file such registration statement or provide such a prospectus, and the early settlement right will not be available, until we have publicly disclosed such transaction or development; *provided* that we will use commercially reasonable efforts to make such disclosure as soon as it is commercially reasonable to do so). In the event that a holder seeks to exercise its early settlement right and a registration statement is required to be effective in connection with the exercise of such right but no such registration statement is then effective, the holder's exercise of such right will be void unless and until such a registration statement is effective.

Upon early settlement, except as described below in "-Early Settlement Upon a Fundamental Change," we will sell, and the holder will be entitled to buy, the minimum settlement rate of 0.5021 shares of our common stock (or in the case of an early settlement following a reorganization event, such number of exchange property units, as described under "-Reorganization Events" below) for each purchase contract being settled (regardless of the market price of our common stock on the date of early settlement), subject to adjustment under the circumstances described under "-Anti-dilution Adjustments" below. We will cause, no later than the second business day after the applicable early settlement date, (1) the shares of our common stock to be issued and (2) the related Notes or applicable ownership interests in the Treasury portfolio or Treasury securities, as the case may be, underlying the Equity Units and securing such purchase contracts to be released from the pledge under the purchase contract and pledge agreement, and delivered to the purchase contract agent for delivery to the holder. Upon early settlement, the holder will be entitled to receive any accrued and unpaid contract adjustment payments (including any accrued and unpaid deferred contract adjustment payments and compounded contract adjustment payments thereon) to, but excluding, the contract adjustment payment date immediately preceding the early settlement date. The holder's right to receive future contract adjustment payments will also terminate.

If the purchase contract agent receives a completed "Election to Settle Early" form (along with the Corporate Unit or Treasury Unit certificate, if they are in certificated form) and payment of $50.00 for each purchase contract being settled (and, if required, an amount equal to the contract adjustment payments payable on the next contract adjustment payment date) prior to 4:00 p.m., New York City time, on any business day and all conditions to early settlement have been satisfied, then that day will be considered the early settlement date. If the purchase contract agent receives the foregoing at or after 4:00 p.m., New York City time, on any business day or at any time on a day that is not a business day, then the next business day will be considered the early settlement date.

Early Settlement Upon a Fundamental Change

If a "fundamental change" (as defined below) occurs prior to the 30th scheduled trading day preceding the purchase contract settlement date, then, following the fundamental change, each holder of a purchase contract, subject to certain conditions described in this prospectus supplement, will have the right to accelerate and settle the purchase contract early on the fundamental change early settlement date (defined below) at the settlement rate determined as if the applicable market value were determined, for such purpose, based on the market value averaging period starting on the 23rd scheduled trading day prior to the fundamental change early settlement date and ending on the third scheduled trading day immediately preceding the fundamental change early settlement date, plus an additional make-whole amount of shares (such additional make-whole amount of shares being hereafter referred to as the "make-whole shares"). We refer to this right as the "fundamental change early settlement right."

If 20 trading days for our common stock have not occurred during the deemed market value averaging period referred to in the preceding paragraph, all remaining trading days will be deemed to occur on the third scheduled trading day immediately prior to the fundamental change early settlement date and the VWAP of our common stock for each of the remaining trading days will be the VWAP of our common stock on that third scheduled trading day or, if such day is not a trading day, the closing price as of such day.

We will provide each of the holders with a notice of the completion of a fundamental change within four scheduled trading days after the effective date of a fundamental change. The notice will specify (1) a date (subject to postponement as described below, the "fundamental change early settlement date"), which will be at least 26 scheduled trading days after the date of such notice and one business day before the purchase contract settlement date, on which date we will deliver shares of our common stock to holders who exercise the fundamental change early settlement right, (2) the date by which holders must exercise the fundamental change early settlement right, which will be no earlier than the second scheduled trading day before the fundamental change early settlement date, (3) the first scheduled trading day of the deemed market value averaging period, which will be the 23rd scheduled trading day prior to the fundamental change early settlement date, the reference price, the threshold appreciation price and the fixed settlement rates, (4) the amount and kind (per share of common stock) of the cash, securities and other consideration receivable by the holder upon settlement and (5) the amount of accrued and unpaid contract adjustment payments (including any deferred contract adjustment payments and compounded contract adjustment payments thereon), if any, that will be paid upon settlement to holders exercising the fundamental change early settlement right. To exercise the fundamental change early settlement right, you must deliver to the purchase contract agent at the corporate trust office of the purchase contract agent or its agent, in each case, in the Borough of Manhattan, The City of New York, during the period beginning on the date we deliver notice that a fundamental change has occurred and ending at 4:00 p.m., New York City time, on the third scheduled trading day immediately preceding the fundamental change early settlement date (such period, subject to extension as described below, the "fundamental change exercise period"), the certificate evidencing your Corporate Units or Treasury Units if they are held in certificated form, and payment of $50.00 for each purchase contract being settled in immediately available funds.

A "fundamental change" will be deemed to have occurred if any of the following occurs:

(1) a "person" or "group" within the meaning of Section 13(d) of the Exchange Act, as in effect on the issue date of the Corporate Units, has become the direct or indirect "beneficial owner," as defined in Rule 13d-3 under the Exchange Act, of shares of our common stock representing more than 50% of the voting power of our common stock;

(2) (A) we are involved in a consolidation with or merger into any other person, or any merger of another person into us, or any other similar transaction or series of related transactions (other than a merger, consolidation or similar transaction that does not result in the conversion or exchange of outstanding shares of our common stock), in each case, in which 90% or more of the outstanding shares of our common stock are exchanged for or converted into cash, securities or other property, greater than 10% of the value of which consists of cash, securities or other property that is not (or will not be upon or immediately following the effectiveness of such consolidation, merger or other transaction) common stock listed on the New York Stock Exchange, the NASDAQ Global Select Market or the NASDAQ Global Market (or any of their respective successors) or (B) the consummation of any sale, lease or other transfer in one transaction or a series of related transactions of all or substantially all of our consolidated assets to any person other than one of our wholly-owned subsidiaries;

(3) our common stock ceases to be listed on at least one of the New York Stock Exchange, the NASDAQ Global Select Market or the NASDAQ Global Market (or any of their respective successors) or the announcement by any of such exchanges on which our common stock is then listed or admitted for trading that our common stock will no longer be so listed or admitted for trading, unless our common stock has been accepted for listing or admitted for trading on another of such exchanges; or

(4) our shareholders approve our liquidation, dissolution or termination;

provided that a transaction or event or series of related transactions that constitute a fundamental change pursuant to both clauses (1) and (2) above will be deemed to constitute a fundamental change solely pursuant to clause (2) of this definition of "fundamental change."

If you exercise the fundamental change early settlement right, we will deliver to you on the fundamental change early settlement date for each purchase contract with respect to which you have elected fundamental change early settlement, a number of shares (or exchange property units, if applicable) equal to the settlement rate described above plus the additional make-whole shares. In addition, on the fundamental change early settlement date, we will pay you the amount of any accrued and unpaid contract adjustment payments (including any deferred contract adjustment payments and compounded contract adjustment payments thereon) to, but excluding, the fundamental change early settlement date, unless the date on which the fundamental change early settlement right is exercised occurs following any record date and prior to the related scheduled contract adjustment payment date, and we are not deferring the related contract adjustment payment, in which case we will instead pay all accrued and unpaid contract adjustment payments to the holder as of such record date. You will also receive on the fundamental change early settlement date the Notes or the applicable ownership interest in the Treasury portfolio or Treasury securities underlying the Corporate Units or Treasury Units, as the case may be, with respect to which you are effecting a fundamental change early settlement, which, in each case, shall have been released from the pledge under the purchase contract and pledge agreement. If you do not elect to exercise your fundamental change early settlement right, your Corporate Units or Treasury Units will remain outstanding and will be subject to normal settlement on the purchase contract settlement date.

We have agreed that, if required under the U.S. federal securities laws, we will use our commercially reasonable efforts to (1) have in effect throughout the fundamental change exercise period a registration statement covering the common stock and other securities, if any, to be delivered in respect of the purchase contracts being settled and (2) provide a prospectus in connection therewith, in each case in a form that may be used in connection with the fundamental change early settlement (it being understood that for so long as there is a material business transaction or development that has not yet been publicly disclosed (but in no event for a period longer than 90 days), we will not be required to file such registration statement or provide such a prospectus, and the fundamental change early settlement right will not be available, until we have publicly disclosed such transaction or development; *provided* that we will use commercially reasonable efforts to make such disclosure as soon as it is commercially reasonable to do so). In the event that a holder seeks to exercise its fundamental change early settlement right and a registration statement is required to be effective in connection with the exercise of such right but no such registration statement is then effective or a blackout period is continuing, the holder’s exercise of such right will be void unless and until such a registration statement is effective and no blackout period is continuing. The fundamental change exercise period will be extended by the number of days during such period on which no such registration statement is effective or a blackout period is continuing (*provided* that the fundamental change exercise period will not be extended beyond the third scheduled trading day preceding the purchase contract settlement date) and the fundamental change early settlement date will be postponed to the third scheduled trading day following the end of the fundamental change exercise period. We will provide each of the holders with a notice of any such extension and postponement at least 23 scheduled trading days prior to any such extension and postponement.

Unless the Treasury portfolio has replaced the Notes as a component of the Corporate Units as result of a successful remarketing, holders of Corporate Units may exercise the fundamental change early settlement right only in integral multiples of 20 Corporate Units. If the Treasury portfolio has replaced the Notes as a component of Corporate Units, holders of the Corporate Units may exercise the fundamental change early settlement right only in integral multiples of 40,000 Corporate Units.

A holder of Treasury Units may exercise the fundamental change early settlement right only in integral multiples of 20 Treasury Units.

Calculation of Make-Whole Shares. The number of make-whole shares per purchase contract applicable to a fundamental change early settlement will be determined by reference to the table below, based on the date on which the fundamental change occurs or becomes effective (the “effective date”) and the “stock price” in the fundamental change, which will be:

- in the case of a fundamental change described in clause (2) above where the holders of our common stock receive only cash in the fundamental change, the cash amount paid per share of our common stock; or
- otherwise, the average of the closing prices of our common stock over the 20 trading-day period ending on the trading day immediately preceding the effective date of the fundamental change.

	Stock Price on Effective Date														
Effective Date	$30.00	$40.00	$50.00	$70.00	$82.98	$90.00	$99.58	$120.00	$140.00	$160.00	$180.00	$200.00	$220.00	$240.00	$260.00
3/19/2019	0.1277	0.0935	0.0722	0.0334	0.0000	0.0323	0.0664	0.0405	0.0291	0.0234	0.0197	0.0169	0.0147	0.0129	0.0113
3/15/2020	0.0848	0.0621	0.0482	0.0214	0.0000	0.0203	0.0527	0.0274	0.0190	0.0154	0.0131	0.0113	0.0098	0.0086	0.0075
3/15/2021	0.0436	0.0319	0.0249	0.0120	0.0000	0.0096	0.0368	0.0134	0.0095	0.0079	0.0068	0.0058	0.0051	0.0045	0.0039
3/15/2022	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

The stock prices set forth in the second row of the table (i.e., the column headers) will be adjusted upon the occurrence of certain events requiring anti-dilution adjustments to the fixed settlement rates in a manner inversely proportional to the adjustments to the fixed settlement rates.

Each of the make-whole share amounts in the table will be subject to adjustment in the same manner and at the same time as the fixed settlement rates as set forth under "-Anti-dilution Adjustments."

The exact stock price and effective date applicable to a fundamental change may not be set forth on the table, in which case:

- if the stock price is between two stock prices on the table or the effective date is between two effective dates on the table, the amount of make-whole shares will be determined by straight line interpolation between the make-whole share amounts set forth for the higher and lower stock prices and the two effective dates based on a 365-day year, as applicable;
- if the stock price is in excess of $260.00 per share (subject to adjustment in the same manner as the stock prices set forth in the second row of the table as described above), then the make-whole share amount will be zero; and
- if the stock price is less than $30.00 per share (subject to adjustment in the same manner as the stock prices set forth in the second row of the table as described above) (the "minimum stock price"), then the make-whole share amount will be determined as if the stock price equaled the minimum stock price, using straight line interpolation, as described above, if the effective date is between two effective dates on the table.

Notice to Settle with Cash

Unless a termination event has occurred, a holder effects an early settlement or a fundamental change early settlement with respect to the underlying purchase contract, or a successful remarketing has occurred, a holder of Corporate Units may settle the related purchase contract with separate cash by delivering the Corporate Unit certificate, if in certificated form, to the purchase contract agent at the corporate trust office of the purchase contract agent or its agent, in each case, in the Borough of Manhattan, The City of New York with the completed "Notice to Settle with Cash" form at any time on or after the date we give notice of a final remarketing and prior to 4:00 p.m., New York City time on the second business day immediately preceding the first day of the final remarketing period or, if there has been a failed final remarketing, on the second business day immediately preceding the purchase contract settlement date. Holders of Corporate Units may only cash-settle Corporate Units in integral multiples of 20 Corporate Units.

The holder must also deliver to the securities intermediary the required cash payment in immediately available funds. Such payment must be delivered prior to 4:00 p.m., New York City time, on the first business day immediately preceding the final remarketing period or, if there has been a failed remarketing, on the first business day immediately preceding the purchase contract settlement date.

Upon receipt of the cash payment, the related Note will be released from the pledge arrangement and transferred to the purchase contract agent for distribution to the holder of the related Corporate Units. The holder of the Corporate Units will then receive the applicable number of shares of our common stock on the purchase contract settlement date.

If a holder of Corporate Units that has given notice of its election to settle with cash fails to deliver the cash by the applicable time and date specified above, such holder shall be deemed to have consented to the disposition of its Notes in the final remarketing, or to have exercised its put right (as described under "-Remarketing" above), in each case, as applicable.

Any cash received by the collateral agent upon cash settlement may be invested in permitted investments, as defined in the purchase contract and pledge agreement, and the portion of the proceeds equal to the aggregate purchase price of all purchase contracts of such holders will be paid to us on the purchase contract settlement date. Any excess funds received by the collateral agent in respect of permitted investments over the aggregate purchase price remitted to us in satisfaction of the obligations of the holders under the purchase contracts will be distributed to the purchase contract agent for payment to the holders who settled with cash.

Contract Adjustment Payments

Contract adjustment payments in respect of Corporate Units and Treasury Units will be fixed at a rate per year of 2.725% of the stated amount of $50.00 per purchase contract. Contract adjustment payments payable for any period will be computed on the basis of a 360-day year of twelve 30-day months. Contract adjustment payments will accrue from the date of issuance of the purchase contracts and will be payable quarterly in arrears on March 15, June 15, September 15 and December 15 of each year, commencing June 15, 2019.

Contract adjustment payments will be payable to the holders of purchase contracts as they appear on the books and records of the purchase contract agent at the close of business on the relevant record dates, which will be the 30th day of the month immediately preceding the month in which the relevant payment date falls (or, if such day is not a business day, the next preceding business day) or if the Equity Units are held in book-entry form, the "record date" will be the business day immediately preceding the applicable payment date. These distributions will be paid through the purchase contract agent, which will hold amounts received in respect of the contract adjustment payments for the benefit of the holders of the purchase contracts relating to the Equity Units. Subject to any applicable laws and regulations, each such payment will be made as described under "Certain Provisions of the Purchase Contract and Pledge Agreement-Book-Entry System."

If any date on which contract adjustment payments are to be made on the purchase contracts related to the Corporate Units or Treasury Units is not a business day, then payment of the contract adjustment payments payable on that date will be made on the next succeeding day that is a business day, and no interest or payment will be paid in respect of the delay.

For the avoidance of doubt, subject to our right to defer contract adjustment payments, all record holders of purchase contracts on any record date will be entitled to receive the full contract adjustment payment due on the related contract adjustment payment date regardless of whether the holder of such purchase contract elects to settle such purchase contract early (whether at its option or in connection with a fundamental change) following such record date.

Our obligations with respect to contract adjustment payments will be subordinated and junior in right of payment to our obligations under any of our Senior Indebtedness (as defined under "Description of the Junior Subordinated Debentures-Subordination") and will rank on parity with the Notes.

We may, at our option and upon prior written notice to the purchase contract agent, defer all or part of the contract adjustment payments, but not beyond the purchase contract settlement date (or, with respect to an early settlement upon a fundamental change, not beyond the fundamental change early settlement date or, with respect to an early settlement other than upon a fundamental change, not beyond the contract adjustment payment date immediately preceding the early settlement date).

Deferred contract adjustment payments will accrue additional contract adjustment payments at the rate equal to 6.125% per annum (which is equal to the rate of total distributions on the Corporate Units), compounded on each contract adjustment payment date, to, but excluding, the contract adjustment payment date on which such deferred contract adjustment payments are paid. We refer to additional contract adjustment payments that accrue on deferred contract adjustment payments as "compounded contract adjustment payments." We may pay any such deferred contract adjustment payments (including compounded contract adjustment payments thereon) on any scheduled contract adjustment payment date; *provided* that in order to pay deferred contract adjustment payments on any scheduled contract adjustment payment date other than the purchase contract settlement date, we must deliver written notice thereof to holders of the Equity Units and the purchase contract agent on or before the relevant record date. If the purchase contracts are terminated (upon the occurrence of certain events of bankruptcy, insolvency or similar reorganization with respect to us), the right to receive contract adjustment payments and deferred contract adjustment payments (including compounded contract adjustment payments thereon) will also terminate.

If we exercise our option to defer the payment of contract adjustment payments, then, until the deferred contract adjustment payments (including compounded contract adjustment payments thereon) have been paid, we will not (1) declare or pay any dividends on, or make any distributions on, or redeem, purchase or acquire, or make a liquidation payment with respect to, any shares of our capital stock, (2) make any payment of principal of, or interest or premium, if any, on, or repay, repurchase or redeem any of our debt securities that rank on parity with, or junior to, the contract adjustment payments, or (3) make any guarantee payments under any guarantee by us of securities of any of our subsidiaries if our guarantee ranks on parity with, or junior to, the contract adjustment payments.

The restrictions listed above do not apply to:

(a) purchases, redemptions or other acquisitions of our capital stock in connection with any employment contract, benefit plan or other similar arrangement with or for the benefit of employees, officers, directors, agents or consultants or a stock purchase or dividend reinvestment plan, or the satisfaction of our obligations pursuant to any contract or security outstanding on the date that the contract adjustment payment is deferred requiring us to purchase, redeem or acquire our capital stock;

(b) any payment, repayment, redemption, purchase, acquisition or declaration of dividends described in clause (1) above as a result of a reclassification of our capital stock, or the exchange or conversion of all or a portion of one class or series of our capital stock, for another class or series of our capital stock;

(c) the purchase of fractional interests in shares of our capital stock pursuant to the conversion or exchange provisions of our capital stock or the security being converted or exchanged, or in connection with the settlement of stock purchase contracts outstanding on the date that the contract adjustment payment is deferred;

(d) dividends or distributions paid or made in our capital stock (or rights to acquire our capital stock), or repurchases, redemptions or acquisitions of capital stock in connection with the issuance or exchange of capital stock (or of securities convertible into or exchangeable for shares of our capital stock) and distributions in connection with the settlement of stock purchase contracts outstanding on the date that the contract adjustment payment is deferred;

(e) redemptions, exchanges or repurchases of, or with respect to, any rights outstanding under a shareholder rights plan outstanding on the date that the contract adjustment payment is deferred or the declaration or payment thereunder of a dividend or distribution of or with respect to rights in the future;

(f) payments on the Notes, any trust preferred securities, subordinated debentures, junior subordinated debentures or junior subordinated notes, or any guarantees of any of the foregoing, in each case, that rank equal in right of payment to the contract adjustment payments, so long as the amount of payments made on account of such securities or guarantees and the purchase contracts is paid on all such securities and guarantees and the purchase contracts then outstanding on a pro rata basis in proportion to the full payment to which each series of such securities, guarantees or purchase contracts is then entitled if paid in full; *provided* that, for the avoidance of doubt, we will not be permitted under the purchase contract and pledge agreement to make contract adjustment payments in part; or

(g) any payment of deferred interest or principal on, or repayment, redemption or repurchase of, parity or junior securities that, if not made, would cause us to breach the terms of the instrument governing such parity or junior securities.

Anti-dilution Adjustments

Each fixed settlement rate will be subject to the following adjustments:

(1) *Stock Dividends*. If we pay or make a dividend or other distribution on our common stock in common stock, each fixed settlement rate in effect at the opening of business on the day following the date fixed for the determination of stockholders entitled to receive such dividend or other distribution will be increased by dividing:

- each fixed settlement rate by

- a fraction, the numerator of which will be the number of shares of our common stock outstanding at the close of business on the date fixed for such determination and the denominator of which will be the sum of such number of shares and the total number of shares constituting the dividend or other distribution.

If any dividend or distribution in this paragraph (1) is declared but not so paid or made, the new fixed settlement rates shall be readjusted, on the date that our board of directors determines not to pay or make such dividend or distribution, to the fixed settlement rates that would then be in effect if such dividend or distribution had not been declared.

(2) *Stock Purchase Rights*. If we issue to all or substantially all holders of our common stock rights, options, warrants or other securities (other than pursuant to a dividend reinvestment, share purchase or similar plan), entitling them to subscribe for or purchase shares of our common stock for a period expiring within 45 days from the date of issuance of such rights, options, warrants or other securities at a price per share of our common stock less than the current market price (as defined below) calculated as of the date fixed for the determination of stockholders entitled to receive such rights, options, warrants or other securities, each fixed settlement rate in effect at the opening of business on the day following the date fixed for such determination will be increased by dividing:

- each fixed settlement rate by

- a fraction, the numerator of which will be the number of shares of our common stock outstanding at the close of business on the date fixed for such determination plus the number of shares of our common stock which the aggregate consideration expected to be received by us upon the exercise of such rights, options, warrants or other securities would purchase at such current market price and the denominator of which will be the number of shares of our common stock outstanding at the close of business on the date fixed for such determination plus the number of shares of our common stock so offered for subscription or purchase.

If any right, option, warrant or other security described in this paragraph (2) is not exercised or converted prior to the expiration of the exercisability or convertibility thereof (and as a result no additional shares of common stock are delivered or issued pursuant to such right, option, or warrant or other security), the new fixed settlement rates shall be readjusted, as of the date of such expiration, to the fixed settlement rates that would then be in effect had the increase with respect to the issuance of such rights, options, warrants or other securities been made on the basis of delivery or issuance of only the number of shares of common stock actually delivered.

For purposes of this clause (2), in determining whether any rights, options, warrants or other securities entitle the holders to subscribe for or purchase shares of the common stock at a price per share of our common stock less than the current market price on the date fixed for the determination of stockholders entitled to receive such rights, options, warrants or other securities, and in determining the aggregate price payable to exercise such rights, options, warrants or other securities, there shall be taken into account any consideration received by us for such rights, options, warrants or other securities and any amount payable on exercise or conversion thereof, the value of such consideration, if other than cash, to be determined in good faith by our board of directors.

(3) *Stock Splits; Reverse Splits; and Combinations*. If outstanding shares of our common stock shall be subdivided, split or reclassified into a greater number of shares of common stock, each fixed settlement rate in effect at the opening of business on the day following the day upon which such subdivision, split or reclassification becomes effective shall be proportionately increased, and, conversely, in case outstanding shares of our common stock shall each be combined or reclassified into a smaller number of shares of common stock, each fixed settlement rate in effect at the opening of business on the day following the day upon which such combination or reclassification becomes effective shall be proportionately reduced.

(4) *Debt, Asset or Security Distributions*. If we, by dividend or otherwise, distribute to all or substantially all holders of our common stock evidences of our indebtedness, assets or

securities or any rights, options or warrants (or similar securities) to subscribe for, purchase or otherwise acquire evidences of our indebtedness, other assets or property of ours or other securities (but excluding any rights, options, warrants or other securities referred to in paragraph (2) above, any dividend or distribution paid exclusively in cash referred to in paragraph (5) below (in each case, whether or not an adjustment to the fixed settlement rates is required by such paragraph) and any dividend paid in shares of capital stock of any class or series, or similar equity interests, of or relating to a subsidiary or other business unit of ours in the case of a spin-off referred to below, or dividends or distributions referred to in paragraph (1) above), each fixed settlement rate in effect immediately prior to the close of business on the date fixed for the determination of stockholders entitled to receive such dividend or distribution shall be increased by dividing:

- each fixed settlement rate by

- a fraction, the numerator of which shall be the current market price of our common stock calculated as of the date fixed for such determination less the then fair market value (as determined in good faith by our board of directors) of the portion of the assets, securities or evidences of indebtedness so distributed applicable to one share of our common stock and the denominator of which shall be such current market price.

Notwithstanding the foregoing, if the then fair market value (as determined in good faith by our board of directors) of the portion of the assets, securities or evidences of indebtedness so distributed applicable to one share of our common stock exceeds the current market price of our common stock on the date fixed for the determination of stockholders entitled to receive such distribution, in lieu of the foregoing increase, each holder of a purchase contract shall receive, for each purchase contract, at the same time and upon the same terms as holders of shares of our common stock, the amount of such distributed assets, securities or evidences of indebtedness that such holder would have received if such holder owned a number of shares of our common stock equal to the maximum settlement rate on the record date for such dividend or distribution.

In the case of the payment of a dividend or other distribution on our common stock of shares of capital stock of any class or series, or similar equity interests, of or relating to a subsidiary or other business unit of ours, which are or will, upon issuance, be listed on a U.S. securities exchange or quotation system, which we refer to as a "spin-off," each fixed settlement rate in effect immediately before the close of business on the date fixed for determination of stockholders entitled to receive that dividend or distribution will be increased by dividing:

- each fixed settlement rate by

- a fraction, the numerator of which is the current market price of our common stock and the denominator of which is such current market price plus the fair market value, determined as described below, of those shares of capital stock or similar equity interests so distributed applicable to one share of common stock.

The adjustment to the fixed settlement rate under the preceding paragraph will occur on:

- the 10th trading day from and including the effective date of the spin-off; or

- if the spin-off is effected simultaneously with an initial public offering of the securities being distributed in the spin-off and the ex-date for the spin-off occurs on or before the date that the initial public offering price of the securities being distributed in the spin-off is determined, the issue date of the securities being offered in such initial public offering.

For purposes of this section, "initial public offering" means the first time securities of the same class or type as the securities being distributed in the spin-off are offered to the public for cash.

Subject to the immediately following paragraph, the fair market value of the securities to be distributed to holders of our common stock means the average of the closing sale prices of those securities on the principal U.S. securities exchange or quotation system on which such securities are listed or quoted at that time over the first 10 trading days following the effective date of the spin-off. Also, for purposes of such a spin-off, the current market price of our common stock means the average of the closing sale prices of our common stock on the principal U.S. securities exchange or quotation system on which our common stock is listed or quoted at that time over the first 10 trading days following the effective date of the spin-off.

If, however, an initial public offering of the securities being distributed in the spin-off is to be effected simultaneously with the spin-off and the ex-date for the spin-off occurs on or before the date that the initial public offering price of the securities being distributed in the spin-off is determined, the fair market value of the securities being distributed in the spin-off means the initial public offering price, while the current market price of our common stock means the closing sale price of our common stock on the principal U.S. securities exchange or quotation system on which our common stock is listed or quoted at that time on the trading day on which the initial public offering price of the securities being distributed in the spin-off is determined.

If any dividend or distribution described in this paragraph (4) is declared but not so paid or made, the new fixed settlement rates shall be readjusted, as of the date our board of directors determines not to pay or make such dividend or distribution, to the fixed settlement rates that would then be in effect if such dividend or distribution had not been declared.

(5) *Cash Distributions*. If we, by dividend or otherwise, make distributions to all or substantially all holders of our common stock exclusively in cash during any quarterly period in an amount that exceeds $0.67 per share per quarter in the case of a regular quarterly dividend (such per share amount being referred to as the "reference dividend"), then immediately after the close of business on the date fixed for determination of the stockholders entitled to receive such distribution, each fixed settlement rate in effect immediately prior to the close of business on such date will be increased by dividing:

- each fixed settlement rate by
- a fraction, the numerator of which will be equal to the current market price on the date fixed for such determination less the amount, if any, by which the per share amount of the distribution exceeds the reference dividend and the denominator of which will be equal to such current market price.

Notwithstanding the foregoing, if (1) the amount by which the per share amount of the cash distribution exceeds the reference dividend exceeds (2) the current market price of our common stock on the date fixed for the determination of stockholders entitled to receive such distribution, in lieu of the foregoing increase, each holder of a purchase contract shall receive, for each purchase contract, at the same time and upon the same terms as holders of shares of our common stock, the amount of distributed cash that such holder would have received if such holder owned a number of shares of our common stock equal to the maximum settlement rate on the record date for such cash dividend or distribution.

The reference dividend will be subject to an inversely proportional adjustment whenever each fixed settlement rate is adjusted, other than pursuant to this paragraph (5). For the avoidance of doubt, the reference dividend will be zero in the case of a cash dividend that is not a regular quarterly dividend.

If any dividend or distribution described in this paragraph (5) is declared but not so paid or made, the new fixed settlement rate shall be readjusted, as of the date our board of directors determines not to pay or make such dividend or distribution, to the fixed settlement rate that would then be in effect if such dividend or distribution had not been declared.

(6) *Tender and Exchange Offers*. In the case that a tender offer or exchange offer made by us or any subsidiary for all or any portion of our common stock shall expire and such tender or exchange offer (as amended through the expiration thereof) requires the payment to stockholders (based on the acceptance (up to any maximum specified in the terms of the tender offer or exchange offer) of purchased shares) of an aggregate consideration having a fair market value per share of our common stock that exceeds the closing price of our common stock on the trading day next succeeding the last date on which tenders or exchanges may be made pursuant to such tender offer or exchange offer, then, immediately prior to the opening of business on the day after the date of the last time (which we refer to as the "expiration time") tenders or exchanges could have been made pursuant to such tender offer or exchange offer (as amended through the expiration thereof), each fixed settlement rate in effect immediately prior to the close of business on the date of the expiration time will be increased by dividing:

- each fixed settlement rate by

- a fraction (1) the numerator of which will be equal to (a) the product of (i) the current market price on the date of the expiration time and (ii) the number of shares of common stock outstanding (including any tendered or exchanged shares) on the date of the expiration time less (b) the amount of cash plus the fair market value of the aggregate consideration payable to stockholders pursuant to the tender offer or exchange offer (assuming the acceptance by us of purchased shares (as defined below)), and (2) the denominator of which will be equal to the product of (a) the current market price on the date of the expiration time and (b) the result of (i) the number of shares of our common stock outstanding (including any tendered or exchanged shares) on the date of the expiration time less (ii) the number of all shares validly tendered, not withdrawn and accepted for payment on the date of the expiration time (such actually validly tendered or exchanged shares, up to any maximum acceptance amount specified by us in the terms of the tender offer or exchange offer, being referred to as the "purchased shares").

For purposes of paragraphs (2) through (6) (except as otherwise expressly provided therein with respect to spin-offs) above, the "current market price" per share of our common stock or any other security on any day means the average VWAP of our common stock or such other security on the principal U.S. securities exchange or quotation system on which our common stock or such other security, as applicable, is listed or quoted at that time for the 10 consecutive trading days preceding the earlier of the trading day preceding the day in question and the trading day before the "ex-date" with respect to the issuance or distribution requiring such computation. For purposes of paragraph (6) above, the last day of the measurement period shall be the trading day next succeeding the last date on which tenders or exchanges may be made pursuant to the relevant tender offer or exchange offer. The term "ex-date," when used with respect to any issuance or distribution on our common stock or any other security, means the first date on which our common stock or such other security, as applicable, trades, regular way, on the principal U.S. securities exchange or quotation system on which our common stock or such other security, as applicable, is listed or quoted at that time, without the right to receive the issuance or distribution.

We currently do not have a shareholders rights plan with respect to our common stock. To the extent that we have a shareholders rights plan involving the issuance of share purchase rights or other similar rights to all or substantially all holders of our common stock in effect upon settlement of a purchase contract, you will receive, in addition to the common stock issuable upon settlement of any purchase contract, the related rights for the common stock under the shareholders rights plan, unless, prior to any settlement of a purchase contract, the rights have separated from the common stock, in which case each fixed settlement rate will be adjusted at the time of separation as if we made a distribution to all holders of our common stock as described in clause (4) above, subject to readjustment in the event of the expiration, termination or redemption of the rights under the shareholder rights plan.

You may be treated as receiving a constructive distribution from us with respect to the purchase contract if (1) the fixed settlement rates are adjusted (or fail to be adjusted) and, as a result of the adjustment (or failure to adjust), your proportionate interest in our assets or earnings and profits is increased, and (2) the adjustment (or failure to adjust) is not made pursuant to a bona fide, reasonable anti-dilution formula. For example, if the fixed settlement rate is adjusted as a result of a distribution that is taxable to the holders of our common stock, such as a cash dividend, you will be deemed to have received a "constructive distribution" of our stock. Thus, under certain circumstances, an adjustment to the fixed settlement rates might give rise to a taxable dividend to you even though you will not receive any cash in connection with such adjustment. In addition, non-U.S. holders (as defined in "Certain United States Federal Income and Estate Tax Consequences") may, in certain circumstances, be deemed to have received a distribution subject to U.S. federal withholding tax. See "Certain United States Federal Income and Estate Tax Consequences-U.S. Holders-Purchase Contracts" and "Certain United States Federal Income and Estate Tax Consequences-Non-U.S. Holders-Dividends."

In addition, we may increase the fixed settlement rates if our board of directors deems it advisable to avoid or diminish any income tax to holders of our common stock resulting from any dividend or distribution of shares (or rights to acquire shares) or from any event treated as a dividend or distribution for income tax purposes or for any other reasons. We may only make such a discretionary adjustment if we make the same proportionate adjustment to each fixed settlement rate.

Adjustments to the fixed settlement rates will be calculated to the nearest ten thousandth of a share. No adjustment to the fixed settlement rates will be required unless the adjustment would require an increase or decrease of at least one percent in one or both fixed settlement rates. If any adjustment is not required to be made because it would not change one or both fixed settlement rates by at least one percent, then the adjustment will be carried forward and taken into account in any subsequent adjustment. All anti-dilution adjustments will be made not later than each day of any market value averaging period and the time at which we are otherwise required to determine the relevant settlement rate or amount of make-whole shares (if applicable) in connection with any settlement with respect to the purchase contracts.

No adjustment to the fixed settlement rates will be made if holders of Equity Units participate, as a result of holding the Equity Units and without having to settle the purchase contracts that form part of the Equity Units, in the transaction that would otherwise give rise to an adjustment as if they held a number of shares of our common stock equal to the maximum settlement rate, at the same time and upon the same terms as the holders of common stock participate in the transaction.

The fixed settlement rates will not be adjusted (subject to our right to increase them if our board of directors deems it advisable as described in the third preceding paragraph):

- upon the issuance of any shares of our common stock pursuant to any present or future plan providing for the reinvestment of dividends or interest payable on our securities and the investment of additional optional amounts in shares of our common stock under any plan;
- upon the issuance of options, restricted stock or other awards in connection with any employment contract, executive compensation plan, benefit plan or other similar arrangement with or for the benefit of any one or more employees, officers, directors, consultants or independent contractors or the exercise of such options or other awards;
- upon the issuance of any shares of our common stock pursuant to any option, warrant, right or exercisable, exchangeable or convertible security outstanding as of the date the Equity Units were first issued;
- for a change in the par value or no par value of the common stock; or
- for accumulated and unpaid contract adjustment payments.

We will, as promptly as practicable after the fixed settlement rate is adjusted, provide written notice of the adjustment to the holders of Equity Units.

If an adjustment is made to the fixed settlement rates, an adjustment also will be made to the reference price and the threshold appreciation price on an inversely proportional basis solely to determine which of the clauses of the definition of settlement rate will be applicable to determine the settlement rate with respect to the purchase contract settlement date or any fundamental change early settlement date.

If any adjustment to the fixed settlement rates becomes effective, or any effective date, expiration time, ex-date or record date for any stock split or reverse stock split, tender or exchange offer, issuance, dividend or distribution (relating to a required fixed settlement rate adjustment) occurs, during the period beginning on, and including, (1) the open of business on a first trading day of the 20 scheduled trading-day period during which the applicable market value is calculated or (2) in the case of the optional early settlement or fundamental change early settlement, the relevant early settlement date or the date on which the fundamental change early settlement right is exercised and, in each case, ending on, and including, the date on which we deliver shares of our common stock under the related purchase contract, we will make appropriate adjustments to the fixed settlement rates and/or the number of shares of our common stock deliverable upon settlement with respect to the purchase contract, in each case, consistent with the methodology used to determine the anti-dilution adjustments set forth above. If any adjustment to the fixed settlement rates becomes effective, or any effective date, expiration time, ex-date or record date for any stock split or reverse stock split, tender or exchange offer, issuance, dividend or distribution (relating to a required fixed settlement rate adjustment) occurs, during the period used to determine the “stock price” or any other averaging period hereunder, we will make appropriate adjustments to the applicable prices, consistent with the methodology used to determine the anti-dilution adjustments set forth above.

Reorganization Events

The following events are defined as “reorganization events”:

- any consolidation or merger of the Company with or into another person or of another person with or into the Company or a similar transaction (other than a consolidation, merger or similar transaction in which the Company is the continuing corporation and in which the shares of our common stock outstanding immediately prior to the merger or consolidation are not exchanged for cash, securities or other property of the Company or another person);

- any sale, transfer, lease or conveyance to another person of the property of the Company as an entirety or substantially as an entirety, as a result of which the shares of our common stock are exchanged for cash, securities or other property;

- any statutory exchange of the common stock of the Company with another corporation (other than in connection with a merger or acquisition); and

- any liquidation, dissolution or termination of the Company (other than as a result of or after the occurrence of a termination event described below under “-Termination”).

Following the effective date of a reorganization event, the settlement rate shall be determined by reference to the value of an exchange property unit, and we shall deliver, upon settlement of any purchase contract, a number of exchange property units equal to the number of shares of our common stock that we would otherwise be required to deliver. An “exchange property unit” is the kind and amount of common stock, other securities, other property or assets (including cash or any combination thereof) receivable in such reorganization event (without any interest thereon, and without any right to dividends or distribution thereon which have a record date that is prior to the applicable settlement date) per share of our common stock by a holder of common stock that is not a person with which we are consolidated or into which we are merged or which merged into us or to which such sale or transfer was made, as the case may be (we refer to any such person as a “constituent person”), or an affiliate of a constituent person, to the extent such reorganization event provides for different treatment of common stock held by the constituent person and/or the affiliates of the constituent person, on the one hand, and non-affiliates of a constituent person, on the other hand. In the event holders of our common stock (other than any constituent person or affiliate thereof) have the opportunity to elect the form of consideration to be received in such transaction, the exchange property unit that holders of the Corporate Units or Treasury Units are entitled to receive will be deemed to be (1) the weighted average of the types and amounts of consideration received by the holders of our common stock that affirmatively make an election or (2) if no holders of our common stock affirmatively make such an election, the types and amounts of consideration actually received by the holders of our common stock.

In the event of such a reorganization event, the person formed by such consolidation or merger or the person which acquires our assets shall execute and deliver to the purchase contract agent an agreement providing that the holder of each Equity Unit that remains outstanding after the reorganization event (if any) shall have the rights described in the preceding paragraph. Such supplemental agreement shall provide for adjustments to the amount of any securities constituting all or a portion of an exchange property unit and/or adjustments to the fixed settlement rates, which, for events subsequent to the effective date of such reorganization event, shall be as nearly equivalent as may be practicable to the adjustments provided for under “-Anti-dilution Adjustments” above. The provisions described in the preceding two paragraphs shall similarly apply to successive reorganization events.

In connection with any reorganization event, we will also adjust the reference dividend based on the number of shares of common stock comprising an exchange property unit and (if applicable) the value of any non-stock consideration comprising an exchange property unit. If an exchange property unit is composed solely of non-stock consideration, the reference dividend will be zero.

Termination

The purchase contract and pledge agreement provides that the purchase contracts and the obligations and rights of us and of the holders of Corporate Units and Treasury Units thereunder (including the holders' obligation and right to purchase and receive shares of our common stock and to receive accrued and unpaid contract adjustment payments, including deferred contract adjustment payments and compounded contract adjustment payments thereon) will immediately and automatically terminate upon the occurrence of a termination event (as defined below).

Upon any termination event, the Equity Units will represent the right to receive the Notes underlying the undivided beneficial interest in the Notes, applicable ownership interests in the Treasury Portfolio, or the Treasury securities, as the case may be, forming part of such Equity Units. Upon the occurrence of a termination event, we will promptly give the purchase contract agent, the collateral agent and the holders notice of such termination event and the collateral agent will release the related interests in the Notes, applicable ownership interests in the Treasury portfolio or Treasury securities, as the case may be, from the pledge arrangement and transfer such interests in the Notes, applicable ownership interests in the Treasury portfolio or Treasury securities to the purchase contract agent for distribution to the holders of Corporate Units and Treasury Units. If a holder is entitled to receive Notes in an aggregate principal amount that is not an integral multiple of $1,000, the purchase contract agent may request that we issue Notes in denominations of $50.00 and integral multiples thereof in exchange for Notes in denominations of $1,000 or integral multiples thereof. In addition, if any holder is entitled to receive, with respect to its applicable ownership interests in the Treasury portfolio or its pledged Treasury securities, any securities having a principal amount at maturity of less than $1,000, the purchase contract agent will dispose of such securities for cash and pay the cash received to the holder in lieu of such applicable ownership in the Treasury portfolio or such Treasury securities. Upon any termination event, however, such release and distribution may be subject to a delay. In the event that the Company becomes the subject of a case under the U.S. Bankruptcy Code, such delay may occur as a result of the automatic stay under the U.S. Bankruptcy Code and continue until such automatic stay has been lifted. Moreover, claims arising out of the Notes will be subject to the equitable jurisdiction and powers of the bankruptcy court.

A "termination event" means any of the following events with respect to the Company:

(1) at any time on or prior to the purchase contract settlement date, a decree or order by a court having jurisdiction in the premises shall have been entered adjudicating the Company a bankrupt or insolvent, or approving as properly filed a petition seeking reorganization arrangement, adjustment or composition of or in respect of the Company under the U.S. Bankruptcy Code or any other similar applicable federal or state law and such decree or order shall have been entered more than 90 days prior to the purchase contract settlement date and shall have continued undischarged and unstayed for a period of 90 consecutive days;

(2) at any time on or prior to the purchase contract settlement date, a decree or order of a court having jurisdiction in the premises shall have been entered for the appointment of a receiver, liquidator, trustee, assignee, sequestrator or other similar official in bankruptcy or insolvency of the Company or of all or any substantial part of the Company's property, or for the winding up or liquidation of the Company's affairs, and such decree or order shall have been entered more than 90 days prior to the purchase contract settlement date and shall have continued undischarged and unstayed for a period of 90 consecutive days; or

(3) at any time on or prior to the purchase contract settlement date, the Company shall institute proceedings to be adjudicated a bankrupt or insolvent, or shall consent to the institution of bankruptcy or insolvency proceedings against it, or shall file a petition or answer or consent seeking reorganization under the U.S. Bankruptcy Code or any other similar applicable federal or state law, or shall consent to the filing of any such petition, or shall consent to the appointment of a receiver, liquidator, trustee, assignee, sequestrator or other similar official of the Company or of all or any substantial part of the Company's property, or shall make an

assignment for the benefit of creditors, or shall admit in writing its inability to pay its debts generally as they become due.

Pledged Securities and Pledge

The undivided beneficial ownership interests in the Notes, or, following a successful optional remarketing, the applicable ownership interests in the Treasury portfolio (as described under the first bullet of the definition of "Treasury portfolio"), that are a component of the Corporate Units or, if substituted, the beneficial ownership interest in the Treasury securities that are a component of the Treasury Units, collectively, the "pledged securities," will be pledged to the collateral agent for our benefit pursuant to the purchase contract and pledge agreement to secure your obligation to purchase shares of our common stock under the related purchase contracts. The rights of the holders of the Corporate Units and Treasury Units with respect to the pledged securities will be subject to our security interest therein. No holder of Corporate Units or Treasury Units will be permitted to withdraw the pledged securities related to such Corporate Units or Treasury Units from the pledge arrangement except:

- in the case of Corporate Units, to substitute a Treasury security for the related Note, as provided under "Description of the Equity Units-Creating Treasury Units by Substituting a Treasury Security for a Note;"

- in the case of Treasury Units, to substitute a Note for the related Treasury security, as provided under "Description of the Equity Units-Recreating Corporate Units;" and

- upon early settlement, settlement through the payment of separate cash or termination of the related purchase contracts.

Subject to our security interest and the terms of the purchase contract and pledge agreement, each holder of a Corporate Unit (unless the Treasury portfolio has replaced the Notes as a component of the Corporate Unit), will be entitled through the purchase contract agent and the collateral agent to all of the proportional rights and preferences of the related Notes (including distribution, voting, redemption, repayment and liquidation rights). Each holder of Treasury Units and each holder of Corporate Units (if the Treasury portfolio has replaced the Notes as a component of the Corporate Units), will retain beneficial ownership of the related Treasury securities or the applicable ownership interests in the Treasury portfolio, as applicable, pledged in respect of the related purchase contracts. We will have no interest in the pledged securities other than our security interest.

Except as described in "Certain Provisions of the Purchase Contract and Pledge Agreement-General," upon receipt of distributions on the pledged securities, the collateral agent will distribute such payments to the purchase contract agent, which in turn will distribute those payments to the holders in whose names the Corporate Units or Treasury Units are registered at the close of business on the record date for the distribution.

CERTAIN PROVISIONS OF THE PURCHASE CONTRACT AND PLEDGE AGREEMENT

In this Description of the Purchase Contract and Pledge Agreement, "AEP," "we," "us," "our" and the "Company" refer only to American Electric Power Company, Inc. and any successor obligor, and not to any of its subsidiaries.

The following is a summary of some of the other terms of the purchase contract and pledge agreement. The summary contains a description of additional material terms of the agreement but is only a summary and is not complete. This summary is subject to and is qualified by reference to all the provisions of the purchase contract and pledge agreement, including the definitions of certain terms used *therein, the form of which has been or will be filed and incorporated by reference as an exhibit to the registration statement of which this prospectus supplement and the accompanying base prospectus form a part.*

General

Payments on the Corporate Units and Treasury Units will be payable, the purchase contracts will be settled, and transfers of the Corporate Units and Treasury Units will be registrable at, the office of the purchase contract agent or its agent, in each case, in the Borough of Manhattan, The City of New York. In addition, if the Corporate Units or Treasury Units do not remain in book-entry form, we will make payments on the Corporate Units and Treasury Units by check mailed to the address of the person entitled thereto as shown on the security register or by a wire transfer to the account designated by the holder by a prior written notice.

Shares of common stock will be delivered on the purchase contract settlement date (or earlier upon early settlement), or, if the purchase contracts have terminated, the related pledged securities will be delivered (subject to delays, including potentially as a result of the imposition of the automatic stay under the U.S. Bankruptcy Code, as described under "Description of the Purchase Contracts-Termination") at the office of the purchase contract agent or its agent upon presentation and surrender of the applicable Corporate Unit or Treasury Unit certificate, if in certificated form.

If Corporate Units or Treasury Units are in certificated form and the holder fails to present and surrender the certificate evidencing the Corporate Units or Treasury Units to the purchase contract agent on or prior to the purchase contract settlement date, the shares of common stock issuable upon settlement with respect to the related purchase contract will be registered in the name of the purchase contract agent or its nominee. The shares, together with any distributions, will be held by the purchase contract agent as agent for the benefit of the holder until the certificate is presented and surrendered or the holder provides satisfactory evidence that the certificate has been destroyed, lost or stolen, together with any indemnity that may be required by the purchase contract agent and us.

If the purchase contracts terminate prior to the purchase contract settlement date, the related pledged securities are transferred to the purchase contract agent for distribution to the holders, and a holder fails to present and surrender the certificate evidencing the holder's Corporate Units or Treasury Units, if in certificated form, to the purchase contract agent, the related pledged securities delivered to the purchase contract agent and payments on the pledged securities will be held by the purchase contract agent as agent for the benefit of the holder until the applicable certificate is presented, if in certificated form, or the holder provides the evidence and indemnity described above.

No service charge will be made for any registration of transfer or exchange of the Corporate Units or Treasury Units, except for any tax or other governmental charge that may be imposed in connection therewith.

The purchase contract agent will have no obligation to invest or to pay interest on any amounts it holds pending payment to any holder.

Modification

The purchase contract and pledge agreement will contain provisions permitting us, the purchase contract agent and the collateral agent, to modify the purchase contract and pledge agreement without the consent of the holders for any of the following purposes:

- to evidence the succession of another person to our obligations;

- to add to the covenants for the benefit of holders or to surrender any of our rights or powers under the purchase contract and pledge agreement;

- to evidence and provide for the acceptance of appointment of a successor purchase contract agent or a successor collateral agent or securities intermediary;

- to make provision with respect to the rights of holders pursuant to the requirements applicable to reorganization events;

- to cure any ambiguity or to correct or supplement any provisions that may be inconsistent with any other provision in the purchase contract and pledge agreement;

- to make such other provisions in regard to matters or questions arising under the purchase contract and pledge agreement that do not materially and adversely affect the rights of any holders of Equity Units; and

- to conform the provisions of the purchase contract and pledge agreement to the description of such agreement, the Equity Units and the purchase contracts contained in the preliminary prospectus supplement for the Equity Units as supplemented and/or amended by the related pricing term sheet.

The purchase contract and pledge agreement will contain provisions allowing us, the purchase contract agent and the collateral agent, subject to certain limited exceptions, to modify the terms of the purchase contracts or the purchase contract and pledge agreement with the consent of the holders of not less than a majority of the outstanding Equity Units, with holders of Corporate Units and Treasury Units voting as a single class. However, no such modification may, without the consent of the holder of each outstanding purchase contract affected thereby:

- subject to our right to defer contract adjustment payments, change any payment date;

- impair the holders' right to institute suit for the enforcement of a purchase contract or payment of any contract adjustment payments (including compounded contract adjustment payments);

- except as required pursuant to any anti-dilution adjustment, reduce the number of shares of our common stock purchasable under a purchase contract, increase the purchase price of the shares of our common stock on settlement of any purchase contract, change the purchase contract settlement date or change the right to early settlement or fundamental change early settlement in a manner adverse to the rights of the holders or otherwise adversely affect the holder's rights under any purchase contract, the purchase contract and pledge agreement or remarketing agreement in any respect;

- increase the amount or change the type of collateral required to be pledged to secure a holder's obligations under the purchase contract and pledge agreement;

- impair the right of the holder of any purchase contract to receive distributions on the collateral, or otherwise adversely affect the holder's rights in or to such collateral;

- reduce any contract adjustment payments or any deferred contract adjustment payments (including compounded contract adjustment payments) or change any place where, or the coin or currency in which, any contract adjustment payment is payable; or

- reduce the percentage of the outstanding purchase contracts whose holders' consent is required for the modification, amendment or waiver of the provisions of the purchase contracts and the purchase contract and pledge agreement.

However, if any amendment or proposal would adversely affect only the Corporate Units or only the Treasury Units, then only the affected class of holders will be entitled to vote on such amendment or proposal, and such amendment or proposal will not be effective except with the consent of the holders of not less than a majority of such class or, if referred to in the seven bullets above, each holder affected thereby.

No Consent to Assumption

Each holder of a Corporate Unit or a Treasury Unit will be deemed under the terms of the purchase contract and pledge agreement, by the purchase of such Corporate Unit or Treasury Unit, to have expressly withheld any consent to the assumption under Section 365 of the U.S. Bankruptcy Code or otherwise, of the related purchase contracts by us, our receiver, liquidator or trustee or person or entity performing similar functions in the event that we become a debtor under the U.S. Bankruptcy Code or other similar state or federal law providing for reorganization or liquidation.

Consolidation, Merger and Conveyance of Assets as an Entirety

We will agree not to consolidate with or merge into any other person or convey, transfer or lease our properties and assets substantially as an entirety to any person unless (1) the person formed by such consolidation or into which we merge or the person which acquires by conveyance or transfer, or which leases, our property and assets, substantially as an entirety, is a person organized and existing under the laws of the United States, any state thereof or the District of Columbia, and expressly assumes all of our responsibilities and liabilities under the purchase contracts, the Corporate Units, the Treasury Units, the purchase contract and pledge agreement, the remarketing agreement (if any) and the indenture by one or more supplemental agreements in form satisfactory to the purchase contract agent, the collateral agent and the notes trustee, executed and delivered to the purchase contract agent, the collateral agent and the notes trustee by such corporation, and (2) we or such successor corporation, as the case may be, will not, immediately after such merger or consolidation, or such sale or conveyance, be in default in the performance of any of its obligations or covenants under such agreements.

In case of any such consolidation, merger, sale or conveyance, and upon any such assumption by the successor corporation, such successor corporation shall succeed to and be substituted for us, with the same effect as if it had been named in the purchase contracts, the Corporate Units, the Treasury Units, the purchase contract and pledge agreement and the remarketing agreement (if any) as us and (other than in the case of a lease) we shall be relieved of any further obligation under the purchase contracts, the Corporate Units, the Treasury Units, the purchase contract and pledge agreement and the remarketing agreement (if any).

Title

We, the purchase contract agent and the collateral agent may treat the registered owner of any Corporate Units or Treasury Units as the absolute owner of the Corporate Units or Treasury Units for the purpose of making payment (subject to the record date provisions described above), settling the related purchase contracts and for all other purposes.

Replacement of Equity Unit Certificates

In the event that physical certificates have been issued, any mutilated Corporate Unit or Treasury Unit certificate will be replaced by us at the expense of the holder upon surrender of the certificate to the purchase contract agent at the corporate trust office of the purchase contract agent or its agent, in each case, in the Borough of Manhattan, The City of New York. Corporate Unit or Treasury Unit certificates that become destroyed, lost or stolen will be replaced by us at the expense of the holder upon delivery to us and the purchase contract agent of evidence of their destruction, loss or theft satisfactory to us and the purchase contract agent. In the case of a destroyed, lost or stolen Corporate Unit or Treasury Unit certificate, an indemnity satisfactory to the purchase contract agent and us may be required at the expense of the holder before a replacement certificate will be issued.

Notwithstanding the foregoing, we will not be obligated to issue any Corporate Unit or Treasury Unit certificates on or after the business day immediately preceding the purchase contract settlement date or the date on which the purchase contracts have terminated. The purchase contract and pledge agreement will provide that, in lieu of the delivery of a replacement Corporate Unit or Treasury Unit certificate, the purchase contract agent, upon delivery of the evidence and indemnity described above, will, in the case of the purchase contract settlement date, deliver the shares of common stock issuable pursuant to the purchase contracts included in the Corporate Units or Treasury Units evidenced by the certificate, or, if the purchase contracts have terminated prior to the purchase contract settlement date, transfer the pledged securities included in the Corporate Units or Treasury Units evidenced by the certificate.

Governing Law

The purchase contracts and the purchase contract and pledge agreement and the remarketing agreement will be governed by, and construed in accordance with, the laws of the State of New York.

Information Concerning the Purchase Contract Agent

The Bank of New York Mellon Trust Company, N.A. (or its successor) will be the purchase contract agent. The purchase contract agent will act as the agent for the holders of Corporate Units and Treasury Units. The purchase contract agent will not be obligated to take any discretionary action in connection with a default under the terms of the Corporate Units, the Treasury Units or the purchase contract and pledge agreement.

The purchase contract and pledge agreement will contain provisions limiting the liability of the purchase contract agent. The purchase contract and pledge agreement also will contain provisions under which the purchase contract agent may resign or be replaced. Such resignation or replacement will be effective upon the appointment of a successor.

In addition to serving as the purchase contract agent, The Bank of New York Mellon Trust Company, N.A. will serve as the "notes trustee" for the Notes. We and certain of our affiliates maintain banking relationships with The Bank of New York Mellon Trust Company, N.A. or its affiliates. The Bank of New York Mellon Trust Company, N.A. also serves as trustee under our indentures under which we and certain of our affiliates have issued securities. The Bank of New York Mellon Trust Company, N.A. and its affiliates have purchased, and are likely to purchase in the future, our securities and securities of our affiliates.

Information Concerning the Collateral Agent

The Bank of New York Mellon Trust Company, N.A. (or its successor) will be the collateral agent. The collateral agent will act solely as our agent and will not assume any obligation or relationship of agency or trust for or with any of the holders of the Corporate Units and the Treasury Units except for the obligations owed by a pledgee of property to the owner thereof under the purchase contract and pledge agreement and applicable law.

The purchase contract and pledge agreement will contain provisions limiting the liability of the collateral agent. The purchase contract and pledge agreement also will contain provisions under which the collateral agent may resign or be replaced. Such resignation or replacement will be effective upon the appointment of a successor.

In addition to serving as the collateral agent, The Bank of New York Mellon Trust Company, N.A. will serve as the "notes trustee" for the Notes. We and certain of our affiliates maintain banking relationships with The Bank of New York Mellon Trust Company, N.A. or its affiliates. The Bank of New York Mellon Trust Company, N.A. also serves as trustee under our indentures under which we and certain of our affiliates have issued securities. The Bank of New York Mellon Trust Company, N.A. and its affiliates have purchased, and are likely to purchase in the future, our securities and securities of our affiliates.

Miscellaneous

The purchase contract and pledge agreement will provide that we will, at all times prior to the purchase contract settlement date, reserve and keep available, free from preemptive rights, out of our authorized but unissued common stock the maximum number of shares of our common stock issuable against payment (including the maximum number of make-whole shares issuable upon a fundamental change early settlement) in respect of all purchase contracts included in the Corporate Units or Treasury Units evidenced by the outstanding certificates.

The purchase contract and pledge agreement will provide that we will pay all fees and expenses related to (1) the retention of the purchase contract agent, the collateral agent, the custodial agent and the securities intermediary and (2) any enforcement by the purchase contract agent of the rights of the holders of the Corporate Units and Treasury Units. Holders who elect to substitute the related pledged securities, thereby creating Treasury Units or recreating Corporate Units, however, will be responsible for any fees or expenses payable in connection with such substitution, as well as for any commissions, fees or other expenses incurred in acquiring the pledged securities to be substituted. We will not be responsible for any such fees or expenses. The purchase contract agent shall be under no obligation to exercise any of the rights or powers vested in it by the purchase contract and pledge agreement at the request or direction of any of the holders pursuant to the purchase contract and pledge agreement, unless such holders shall have offered to the purchase contract agent security or indemnity reasonably satisfactory to the purchase contract agent against the costs, expenses and liabilities which might be incurred by it in compliance with such request or direction.

The purchase contract and pledge agreement will also provide that any court of competent jurisdiction may in its discretion require, in any suit for the enforcement of any right or remedy under the purchase contract and pledge agreement, or in any suit against the purchase contract agent for any action taken, suffered or omitted by it as purchase contract agent, the filing by any party litigant in such suit of an undertaking to pay the costs of such suit, and that such court may in its discretion assess reasonable costs, including reasonable attorneys' fees and costs against any party litigant in such suit, having due regard to the merits and good faith of the claims or defenses made by such party litigant. The foregoing shall not apply to any suit instituted by the purchase contract agent, to any suit instituted by any holder, or group of holders, holding in the aggregate more than 10% of the outstanding Equity Units, or to any suit instituted by any holder for the enforcement of any interest on any Notes owed pursuant to such holder's applicable ownership interests in Notes or contract adjustment payments on or after the respective payment date therefor in respect of any Equity Unit held by such holder, or for enforcement of the right to purchase shares of our common stock under the purchase contracts constituting part of any Equity Unit held by such holder.

Exhibit 10(f)(2)(A)

SECOND AMENDMENT TO

AMERICAN ELECTRIC POWER SYSTEM
SUPPLEMENTAL RETIREMENT SAVINGS PLAN
(as Amended and Restated as of January 1, 2011)

This Second Amendment is made by American Electric Power Service Corporation ("AEPSC") to the American Electric Power System Supplemental Retirement Savings Plan (the "Plan"), as amended (including the most recent amendment and restatement effective January 1, 2011, signed December 15, 2010, and an amendment thereto signed December 4, 2014.

WHEREAS, the Plan currently defines "Compensation" by listing various types of pay eligible for deferral under the Plan and capping the amount that may be taken into account during each Plan Year at $2,000,000; and

WHEREAS, the Human Resources Committee of American Electric Power Company, Inc. has authorized the prospective removal of the $2,000,000 cap effective for deferrals of Compensation for the 2020 calendar year (including, for example, annual incentive compensation earned in 2020 and payable in 2021); and

WHEREAS, AEPSC would like to add the option for participants to have their Active Account balance distributed to them in 10 annual installments that commence on a date that is deferred by 5 years from the applicable First Date Available or Next Date Available;

NOW, THEREFORE, the Plan is hereby amended as follows:

1. Section 2.8 of the Plan hereby is amended in its entirety to read as follows:

2.8 "Compensation" means a Participant's regular straight time pay, or base salary or wage including any base wage or salary lump sum payment made as part of the Company's regular compensation program that may be paid in lieu of or in addition to a base wage or salary increase, salary or wage reductions made pursuant to sections 125, 402(e)(3) or 132(f) of the Code and contributions to this Plan, sick pay and salary continuation, overtime pay, shift and Sunday premium payments, safety focus payouts and incentive compensation paid pursuant to the terms of annual incentive compensation plans provided that Compensation shall not include (i) annual incentive compensation attributable to years ending on or before December 31, 2019 in excess of a Plan Year maximum of two million dollars ($2,000,000), (ii) non-annual bonuses (such as but not limited to project bonuses and sign-on bonuses), (iii) severance pay, (iv) relocation payments, (v) employee referral pay, (vi) meal allowance pay, (vii) commissions; or (viii) any other form of additional compensation that is not considered to be part of base salary, base wage, overtime pay or annual incentive compensation. For this purpose, safety focus payouts shall be considered paid pursuant to the terms of an annual incentive plan, although such payouts may be determined and paid on a quarterly basis. Notwithstanding anything stated in the preceding sentences to the contrary, Compensation shall be determined after any deferral thereof pursuant to the American Electric Power System Stock Ownership Requirement Plan, as amended, or pursuant to a pay reduction agreement under the American Electric Power System Incentive Compensation Deferral Plan, as amended.

2. Section 5.1(b)(1)(C) (setting forth certain distribution options for the amount credited to a Participant's Active SRSP Account) is hereby amended by adding thereto to clauses (iii) and (iv), such that it shall read as follows effective for distribution elections or changes to distribution elections made on or after such date as the Committee shall designate:

(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.

3. In all other respects, the terms of the Plan are ratified and confirmed.

IN WITNESS WHEREOF, this Amendment has been executed this 30th day of December, 2019.

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: /s/ Tracy A. Elich
Tracy A. Elich, Vice President - Human Resources

Exhibit 10(e)

AMERICAN ELECTRIC POWER SYSTEM
EXCESS BENEFIT PLAN

(As Amended and Restated as of January 1, 2020)

ARTICLE I
Purposes and Effective Date

1.1 Purpose. The American Electric Power System Excess Benefit Plan is maintained to provide Supplemental Retirement Benefits for eligible employees whose retirement benefits from the Retirement Plan (as defined below) are restricted due to limitations imposed by provisions of the Internal Revenue Code or who are entitled to Supplemental Retirement Benefits under the terms of an employment agreement between the eligible employee and an Associated Company.

1.2 Effective Date. The original effective date of this Plan was January 1, 1990, and the effective date of the changes made by this amended and restated Plan document is January 1, 2020, unless otherwise specified.

ARTICLE II
Definitions

The following terms shall have the meanings set forth in this Article II. Any undefined capitalized term in this Plan shall have the meaning set forth in the Retirement Plan.

2.1 "Accredited Service" means the period of time taken into account under the terms of the Retirement Plan for the purpose of computing a Retirement Plan benefit under the Final Average Pay Formula.

2.2 "Actuarial Equivalence" or "Actuarially Equivalent" will be determined using the assumptions and methods that are used in connection with the Cash Balance Formula under the Retirement Plan, regardless of whether the benefits under this Plan are determined under the Cash Balance Formula.

2.3 "Base Compensation" means a Participant's regular base salary or base wage Earned through the date of the termination of employment of the Participant with the Associated Companies. Base Compensation shall be determined (i) without adjustment for any salary or wage elections made pursuant to Sections 125 (regarding cafeteria plans, including pre-tax contributions for premiums and flexible spending accounts) and 402(e)(3) (regarding elective deferrals, including before-tax contributions under a Section 401(k) retirement savings plan) of the Code, (ii) without reduction for any contributions to the Supplemental Savings Plan; and (iii) excluding bonuses (such as, but not limited to, project bonuses and sign-on bonuses), compensation paid pursuant to the terms of an annual compensation plan, performance pay awards, severance pay, relocation payments, or any other form of additional compensation that is not part of regular base salary or base wage.

2.4 "Beneficiary" means the person or entity designated in accordance with the provisions of Section 7.3, to receive the distribution of death benefits provided for in Article VII.

2.5 "Cash Balance Formula" means the formula under the Retirement Plan by which Participants accrue benefits through credits to his or her Cash Balance Account (as defined in the Retirement Plan). The Cash Balance Formula is effective for Plan Years commencing after December 31, 2000.

2.6 "Code" means the Internal Revenue Code of 1986, as amended from time to time.

2.7 "Commissions" means a periodic incentive directly tied to an individual sale (including sales tied to a deal to which more than one individual is assigned) or quota achievement pursuant to a written and appropriately approved plan that is Earned during the relevant time period, but that is neither a team-based award nor a referral award nor other recognition award nor a part of the Participant's Base Compensation or Incentive Compensation.

2.8 "Committee" means for the period ending May 26, 2004, the Employee Benefit Trusts Committee of the Company. Effective beginning May 27, 2004, the Committee shall be the committee designated by the Company (or by a person duly authorized to act on behalf of the Company) as responsible for the administration of the Plan.

2.9 "Company" means the American Electric Power Service Corporation.

2.10 "Corporation" means the American Electric Power Company, Inc., a New York corporation, and its affiliates and subsidiaries.

2.11 "Determination Date" means the first day of the month immediately following the Participant's Termination.

2.12 "Earned"

(a) when referring to Base Compensation, Commissions and Premium Pay, means the date such amount is paid, and

(b) when referring to Incentive Compensation, means

(i) for purposes of the Cash Balance Formula, the date such amount is paid or such earlier date it would have been paid by an Associated Company if the payment had not been effectively deferred according to the terms of the American Electric Power System Incentive Compensation Deferral Plan or such other applicable plan or agreement; or

(ii) for purposes of the Final Average Pay Formula, the Incentive Compensation shall be considered Earned in equal monthly installments during the applicable period of the calendar year for which the awarded amount had been calculated, without regard to when such amount is paid, provided that the amount ultimately becomes payable to the Participant.

2.13 "Employee" means such persons employed by an Associated Company who are designated in the records of the Associated Company in a classification that is eligible to participate in the Retirement Plan.

2.14 "Employment Contract" means an agreement between an Associated Company and an Employee that provides the Employee with a non-qualified retirement benefit attributable to this Plan.

2.15 "ERISA" means the Employee Retirement Income Security Act of 1974 as amended from time to time.

2.16 "Final Average Pay Formula" means the formula designated as the final average pay formula by the Retirement Plan and by which Participants accrue normal retirement benefits by taking into account the Participant's Accredited Service, average annual earnings and such other factors as are set forth in the Retirement Plan.

2.17 "First Date Available" or "FDA" means (a) with respect to a Participant who is a Key Employee as of the date of such Participant's Termination, the first day of the month next following the date that is six (6) months after the Participant's Termination; and (b) with respect to all other Participants, the first day of the month next following the Participant's Termination.

2.18 "HR Committee" means the Human Resources Committee of the board of directors of the Corporation (or any successor to such committee).

2.19 "Incentive Compensation" means incentive compensation Earned pursuant to the terms of an annual incentive compensation plan, provided that Incentive Compensation shall not include non-annual bonuses (such as but not limited to project bonuses and sign-on bonuses and amounts earned under a long-term incentive plan), severance pay, relocation payments, or any other form of additional compensation that is not considered to be part of Base Compensation.

2.20 "Key Employee" means a Participant who is classified as a "specified employee" at the time of Termination in accordance with policies adopted by 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.

2.21 "Maximum Benefit" means the vested retirement benefit payable from the Retirement Plan under either the Final Average Pay Formula or the Cash Balance Formula, as provided in Article IV and as calculated based upon the Participant's marital status, Beneficiary, credited service, and earnings for services rendered to the Company, to the extent such are permitted by the Code and the Retirement Plan to be taken into account under the Final Average Pay Formula or the Cash Balance Formula, as applicable.

2.22 "Maximum Disability Period" means the last date any disability benefits may become payable under the terms of the American Electric Power System Long-Term Disability Plan in effect as of the later of December 31, 2008 or the last day on which the Participant's initial payment election may be made in accordance with Section 6.3.

2.23 "Next Date Available" or "NDA" means the July 1 of the calendar year immediately following the calendar year in which falls the Participant's Termination.

2.24 "Participant" means any exempt salaried Employee of an Associated Company who has entered the Plan in accordance with Article III of this Plan and has accrued a benefit under the Plan.

2.25 "Associated Company" means the Company and those of its subsidiaries and affiliates of the Corporation who are considered an "Associated Company" as defined under the Retirement Plan.

2.26 "Plan" means this American Electric Power System Excess Benefit Plan, as amended or restated from time to time.

2.27 "Plan Year" means the calendar year commencing each January 1 and ending each December 31.

2.28 "Premium Pay" means overtime pay and shift differential pay that is Earned during the relevant time period, but that is not a part of the Participant's Base Compensation or Incentive Compensation.

2.29 "Present Value" means the current value of a future payment or future stream of payments, calculated using the Applicable Mortality Table and Applicable Interest Rate.

2.30 "Retirement Date" means the date the Participant terminates employment with all Associated Companies after the Participant has attained age 55 and completed at least five years of service with the Associated Companies.

2.31 "Retirement Plan" means the American Electric Power System Retirement Plan, as amended from time to time.

2.32 "Supplemental Retirement Benefit" means the basic retirement benefit determined under Article IV of this Plan.

2.33 "Supplemental Savings Plan" means the American Electric Power System Supplemental Retirement Savings Plan, as amended from time to time.

2.34 "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).

2.35 "Unrestricted Benefit" means the vested retirement benefit that would be payable from the Retirement Plan under either the Final Average Pay Formula or the Cash Balance Formula, as described in Article IV, assuming Sections 401(a)(17) (Compensation Limit) and 415 (Limitation on Benefits) of the Code are not applicable. The calculation of the Unrestricted Benefit also shall take into account other adjustments specified in an Employment Contract.

ARTICLE III
Participation in the Plan

3.1 Eligibility. All exempt salaried Employees of an Associated Company shall be eligible to participate in this Plan so long as such Employee is either (A) entitled to a Supplemental Retirement Benefit under the terms of an Employment Contract, or (B) both (1) a participant in the Retirement Plan, and (2) satisfies one of the following conditions below:

(a) The Employee's Base Compensation for the current or any prior Plan Year exceeds the limitation of Section 401(a)(17) of the Code,

(b) The Employee was a Participant in this Plan as of December 31, 2000,

(c) The Employee's Base Compensation plus Incentive Compensation plus Premium Pay for the current or any prior Plan Year (that begins on or after January 1, 2000, in that such amounts were taken into account for the calendar year 2000 in calculating the opening balance for Participants under the Cash Balance Formula) exceeds the limitation of Section 401(a)(17) of the Code,

(d) The Employee's Base Compensation plus Incentive Compensation plus Commissions plus Premium Pay for the current or any prior Plan Year that begins on or after January 1, 2020 exceeds the limitation of Section 401(a)(17) of the Code, or

(e) Otherwise becomes entitled to a benefit under Article V of this Plan.

To further clarify, an Employee shall not be considered eligible to participate in this Plan so long as such Employee has been continuously eligible to earn additional benefits under the Central and South West System Special Executive Retirement Plan since December 31, 2008, the date that the Central and South West Corporation Cash Balance Retirement Plan was merged with and into the Retirement Plan. Additionally, an eligible Employee may become a Participant if he or she is designated to be a Participant by the Committee. All such eligibility determinations generally shall be made by December 31 of each year or such other time as set forth in an Employee Contract.

3.2 Duration. An Employee who becomes a Participant shall continue to be a Participant until his or her Termination or the date he or she is no longer entitled to receive a Supplemental Retirement Benefit under this Plan.

ARTICLE IV
Benefits

4.1 General Benefits. Upon a Participant's Termination, the Participant shall be entitled to a Supplemental Retirement Benefit calculated as of the Participant's Determination Date, as determined under this Article IV, to the extent vested, to be paid at the time and in the form determined in accordance with Article VI of this Plan. Except as otherwise specified in Article X, a Participant's Supplemental Retirement Benefit shall become vested at the same time and to the same extent as may be provided under the terms of the Retirement Plan. Notwithstanding the foregoing, the amount, calculation methodology, or vesting of a Participant's Supplemental Retirement Benefit may be reduced or otherwise modified in the manner described in an Employment Contract. Additionally, if the Committee determines that a Participant has incurred a liability to, or otherwise damaged, the Corporation, the Company or any Associated Company, the Committee shall have the authority and power, in its sole discretion, to reduce any portion or all of the amounts that might otherwise become payable to such Participant under the terms of this Plan by the amount of such liability or damage, as reasonably determined by the Committee.

4.2 Calculation Methodology. For purposes of calculating the Supplemental Retirement Benefit under Section 4.3 or 4.4 of this Plan, the following rules shall apply. To the extent a Participant's form of benefit under Article VI is a lump sum or installments, this calculation shall be based on the lump sum of the Unrestricted Benefit and Maximum Benefit. To the extent a Participant's form of benefit under Article VI is an annuity, this calculation shall be based on the single life annuity of the Unrestricted Benefit and Maximum Benefit. If a Participant's form of benefit under Article VI is a combination lump sum distribution and life annuity [as set forth in Section 6.2(b)(5)], both calculations shall be made and the appropriate elected percentage applied to each.

4.3 Amount of Benefit for Final Average Pay Participants. A Participant in this Plan whose Retirement Plan benefit takes into account the Final Average Pay Formula shall be entitled to receive a benefit equal to the excess (if any) of the benefit determined under paragraph (a) below over the benefit determined under paragraph (b) below.

(a) The greater of (i) if the Participant's Base Compensation for the current or any prior Plan Year exceeds the limitation of Section 401(a)(17) of the Code, the Unrestricted Benefit calculated (A) using the Final Average Pay Formula and (B) based upon the sum of the rate of the Participant's Base Compensation (as determined from month to month) and Earned Incentive Compensation, or (ii) the Unrestricted Benefit calculated (A) using the Cash Balance Formula and (B) based upon the sum of the Participant's Earned Base Compensation, Earned Incentive Compensation, and Earned Premium Pay; provided however, that

(1) such calculation shall not take into account any amounts Earned with respect to any period after the date of the Participant's Termination with all Associated Companies; and

(2) with regard to Participants who have an annual incentive opportunity in excess of 250% of Base Compensation for the Plan Year in which the Incentive

Compensation is Earned (per Section 2.11(b)(ii)), the amount of Incentive Compensation that will be considered Earned with respect to that Plan Year for purposes of Section 4.3(a)(i) shall not exceed 100% of the highest annualized rate of the Employee's Base Compensation that was in effect with respect to that Employee at any time during that Plan Year; provided, however, that this limitation shall not apply to the extent of any Incentive Compensation provided through the American Electric Power System Senior Officer Incentive Plan; and

(3) for purposes of Section 4.3(a)(ii), the sum of compensation shall be limited to the greater of $1,000,000 or 200% of the Participant's annualized rate of Base Compensation in effect on the last day of the Plan Year (or, if earlier, the date of Termination).

(b) The greater of (1) the Maximum Benefit calculated using the Final Average Pay Formula, or (2) the Maximum Benefit calculated using the Cash Balance Formula.

4.4 Amount of Benefit for Cash Balance Participants. A Participant in this Plan whose Retirement Plan benefit takes into account only the Cash Balance Formula shall be entitled to receive a benefit equal to the excess (if any) of the benefit calculated under paragraph (a) below over the benefit calculated under paragraph (b) below.

(a) The Unrestricted Benefit calculated (A) using the Cash Balance Formula and (B) based upon the sum of the Participant's Earned Base Compensation, Earned Incentive Compensation, Commissions Earned on or after January 1, 2020, and Earned Premium Pay. Effective for amounts paid on or before December 31, 2019, this sum shall be limited to the greater of $1,000,000 or 200% of the Participant's annualized rate of Base Compensation in effect on the last day of the Plan Year (or, if earlier, the date of Termination).

(b) The Maximum Benefit, calculated using the Cash Balance Formula.

4.5 Disability Accruals. Notwithstanding anything in the Plan to the contrary, if a Participant incurs a disability (under the terms of the Retirement Plan), the Participant may continue to accrue a benefit under this Plan from the date of such disability through the Maximum Disability Period to the extent the Participant is receiving such disability accruals under the Retirement Plan, as paid in accordance with Section 6.6.

4.6 Adjustments to Supplemental Retirement Benefit.

(a) The amount of a Participant's Supplemental Retirement Benefit shall be reduced or otherwise modified in the manner described in an Employment Contract (e.g., by any qualified or non-qualified retirement benefits the Participant may be entitled to receive from one or more prior employers).

(b) If the Participant's Unrestricted Benefit under Section 4.3(a) was the amount payable under the Final Average Pay Formula, the following shall apply as of the date

Incentive Compensation is awarded to the Participant, to the extent such Incentive Compensation is attributable to the calendar year that includes the Participant's date of Termination:

(1) The Participant's Determination Date Supplemental Retirement Benefit shall be recalculated to take into account the amount of such Incentive Compensation that is considered Earned during the period ending on such Participant's Termination Date; then

(2) The amount(s) payable to the Participant in accordance with the payment schedule applicable to the Participant as set forth in Section 6.2 shall be increased to reflect the Supplemental Retirement Benefit as recalculated pursuant to paragraph (1); and

(3) To the extent the adjustment to the amount(s) payable to the Participant pursuant to paragraph (2) relates to any amount that had already been paid to the Participant under the applicable payment schedule, the amount of the increase of each such payment shall receive interest credits at the interest rate then being credited for the Cash Balance Formula from the date such original payment had been made through the date of the recalculation, and the aggregate amount of the increases, plus interest, shall be paid in a single sum as soon as administratively practicable.

4.7 Freeze of Benefits. No Participant shall accrue any additional Maximum Benefit or Unrestricted Benefit under the Final Average Pay Formula after December 31, 2010.

ARTICLE V
Enhanced Vested Lump Sum Benefit

5.1 Severance Benefit. The benefits set forth in this Article V shall be treated as a severance benefit under ERISA.

5.2 Eligibility. An Employee who incurs a Termination before age 55 due to a restructuring, consolidation, or downsizing of the Corporation shall be eligible for a special benefit under this Article V if he or she, at the time of Termination, (i) has completed 25 or more years of Accredited Service under the Retirement Plan, or (ii) has attained age 50 and has completed 10 or more years of Accredited Service under the terms of the Retirement Plan.

5.3 Enhanced Supplemental Plan Benefit.

(a) If (i) a Participant described in Section 5.2 has Base Compensation in excess of the limitation under Section 401(a)(17) of the Code for any current or prior Plan Year, (ii) such Participant is entitled to a Supplemental Retirement Benefit calculated under Section 4.3, and (iii) such Participant elects to receive at least some portion of his or her Supplemental Retirement Benefit in the form of an annuity, the Participant shall receive an enhanced vested lump sum benefit equal to the Annuity Portion of the

Present Value of the excess (if any) of the benefit determined under paragraph (1) below over the benefit determined under paragraph (2) below, calculated as of the Determination Date.

(1) The Participant's monthly Unrestricted Benefit calculated as a single life annuity under the Final Average Pay Formula using the early retirement reduction factors from age 65 to age 55 and, if necessary, calculated with a full actuarial reduction from age 55 to the Determination Date, reduced by (but not to an amount less than zero) the Participant's monthly Unrestricted Benefit calculated under Section 4.3(a).

(2) The Participant's monthly Maximum Benefit calculated as a single life annuity under the Final Average Pay Formula with a full actuarial reduction from age 65 to the Determination Date, reduced by (but not to an amount less than zero) the Participant's monthly Maximum Benefit calculated under Section 4.3(b).

(b) For purposes of this Section 5.3, the term "Annuity Portion" means the percentage of the Participant's Supplemental Retirement Benefit that the Participant has elected under Article VI to receive in the form of an annuity.

(c) The special benefit payable hereunder shall be payable in a lump sum as soon as practicable after the annuity benefit under this Plan commences as provided under Article VI. The amount of the lump sum shall be credited with interest at the rate at which Interest Credits are applied under the Retirement Plan from the Determination Date to the date such lump sum is distributed. If the Participant dies before the date of payment and the Participant's Spouse is the Participant's sole Beneficiary, then the Participant's Beneficiary will receive the lump sum payable under this Section 5.3 as soon as practicable after the Participant's death.

ARTICLE VI
Payment of Vested Supplemental Retirement Benefits

6.1 Determination of Supplemental Retirement Benefit. Upon a Participant's Termination for any reason other than the Participant's death, the Participant's Supplemental Retirement Benefit shall be calculated as of the Participant's Determination Date, shall be adjusted in the manner described in Section 4.6, and, to the extent vested, distributed to the Participant in the manner described in Section 6.2. If the Supplemental Retirement Benefit is payable in the form of a lump sum or installments, any unpaid balance shall be credited with interest at the rate at which Interest Credits are applied under the Retirement Plan from the Determination Date until the date of payment.

6.2 General Timing of Payment. A Participant generally is entitled to receive a Supplemental Retirement Benefit upon Termination (or, in a manner specified in an Employment Contract to the extent compliant with Code Section 409A so as to prevent the participant from incurring current federal income tax penalties under Code Section 409A). Payment generally will be made at the following times and in the following forms, as specified in a Participant's payment election as provided under this Article VI.

(a) Elections with Determination Dates On or Before December 1, 2007. Effective with respect to distribution election forms with Determination Dates on or before December 1, 2007, the forms of distribution available to each Participant shall be limited to the following:

(1) A single lump sum distribution

(a) as of the First Date Available; or

(b) as of the Next Date Available; or

(c) as of the fifth anniversary of the First Date Available; or

(d) as of the fifth anniversary of the Next Date Available; or

(2) In five (5) annual installments commencing

(a) as of the First Date Available; or

(b) as of the Next Date Available; or

(c) as of the fifth anniversary of the First Date Available; or

(d) as of the fifth anniversary of the Next Date Available; or

(3) In ten (10) annual installments commencing

(a) as of the First Date Available; or

(b) as of the Next Date Available;

(4) As a single life annuity commencing on the First Date Available, or any Actuarially Equivalent "life annuity," as described in Treasury Regulation 1.409A-2(b)(ii) and as available as an annuity option under the Retirement Plan, but excluding any pop-up feature or level income option under the Retirement Plan.

(5) A combination of a 50% monthly annuity and a 50% lump sum distribution, payable beginning on the First Date Available.

(b) Elections with Determination Dates After December 1, 2007.

(1) A single lump sum distribution

(a) as of the First Date Available; or

(b) as of the Next Date Available; or

(c) as of the fifth anniversary of the First Date Available; or

(d) as of the fifth anniversary of the Next Date Available; or

(2) In five (5) annual installments commencing

(a) as of the First Date Available; or

(b) as of the Next Date Available; or

(c) as of the fifth anniversary of the First Date Available; or

(d) as of the fifth anniversary of the Next Date Available; or

(3) In ten (10) annual installments commencing

(a) as of the First Date Available; or

(b) as of the Next Date Available; or

Effective for distribution elections or changes to distribution elections made on or after such date as the Committee shall designate:

(c) as of the fifth anniversary of the First Date Available; or

(d) as of the fifth anniversary of the Next Date Available.

(4) As a single life annuity commencing on the First Date Available, or any Actuarially Equivalent “life annuity,” as described in Treasury Regulation 1.409A-2(b)(ii) and as available as an annuity option under the Retirement Plan, but excluding any pop-up feature or level income option under the Retirement Plan;

(5) Effective with respect to distribution election forms applicable to Determination Dates on or after January 1, 2009, a combination lump sum distribution and “life annuity” [as described in paragraph (b)(4), above] commencing as of the First Date Available, allocated in one of the following proportions:

(a) 25% as a lump sum distribution and 75% as a life annuity;

(b) 50% as a lump sum distribution and 50% as a life annuity; or

(c) 75% as a lump sum distribution and 25% as a life annuity.

(c) Surviving Spouse Benefit. Notwithstanding the foregoing, the calculation of any annuity shall be enhanced if (1) a Participant is at least age 55 with five (5) years of service at the time of Termination, (2) has been married continuously to his or her Spouse throughout the one-year period ending on the Determination Date, (3) the Participant elected to receive at least a portion of his or her Supplemental Retirement Benefit in the form of an annuity, and (4) the Participant's Final Average Pay Formula provided the greater benefit under Section 4.3(a). The enhanced benefit shall be calculated to provide a fully-subsidized 30% survivor annuity, known as the "Surviving Spouse Benefit," with respect to the percentage of the Participant's Supplemental Retirement Benefit that the Participant has elected under Article VI to receive in the form of an annuity, and shall be determined in the same manner as is set forth under the Retirement Plan.

(d) Key Employees. Notwithstanding the foregoing, with respect to any Participant who is a Key Employee, to the extent that any payments otherwise would have been made in the form of an annuity before the First Date Available, such payments shall be aggregated and paid on the First Date Available.

6.3 Participant Elections. Each Participant in the Plan may make an election as to the time and form of payment of his or her Supplemental Retirement Benefit, as provided in Section 6.2. Participants must make such an election in accordance with the following deadlines.

(a) Generally. Except as otherwise provided in this Plan, a Participant must make his or her payment election by December 31 of the calendar year before the calendar year in which he or she first becomes a Participant in this Plan.

(b) Newly Eligible Participants. If an individual first becomes a Participant during a calendar year, 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 under Section 409A of the Code, the Participant may make an election by no later than the 30th day after becoming a Participant in the Plan.

(c) Excess Benefit Plan Participants. If an individual first becomes a Participant on or after January 1, 2005, and participation in this Plan is considered participation in an "excess benefit plan," the Participant may make an election no later than the 30th day after the last day of the first calendar year in which the Participant satisfied the requirements to become a Participant, provided that such individual has neither an accrued benefit nor been allocated any deferral under any other excess benefit plan. For this purpose, the term "excess benefit plan" means all nonqualified deferred compensation plans in which the individual participates, to the extent such plans do not provide for an election between the current compensation and deferred compensation and solely provide deferred compensation equal to the excess of the benefits the individual would have accrued under a qualified employer plan in which the individual also participates, in the absence of one or more of the limits incorporated into the plan to reflect one or more of the limits on contributions or benefits applicable to the qualified employer plan under the Code, over the benefits the individual actually accrues under the qualified employer plan, as described in Treasury Regulation Section 1.409A-2(a)(7)(iii).

(d) Actuarially Equivalent Life Annuities. A Participant who elected an annuity option described in Section 6.2(b)(4) or (5) of this Plan may make an irrevocable election within 60 days after the Determination Date to receive his or her benefits in the form of any other annuity option available under Section 6.2(b)(4) or (5) of this Plan. If the Participant fails to make a timely election as to the form of annuity, the Participant shall be deemed to have selected a 100% joint and survivor annuity with the Participant's Beneficiary as the survivor annuitant.

(e) Default. If a Participant fails to make an initial payment election in the times provided in this Section 6.3, the Participant shall be deemed to have elected to receive payment of his or her Supplemental Retirement Benefit in a lump sum on the First Date Available.

(f) Examples.

(1) If an individual's Employment Contract is effective May 31, 2009, and the Employment Contract provides that the Participant will receive a Supplemental Retirement Benefit in a manner that causes this Plan not to be considered an Plan for that Participant, the Participant must make a payment election by June 30, 2009.

(2) If an Employee is designated a Participant in 2009 because his or her compensation exceeded the limit under Section 401(a)(17) of the Code as of October 31, 2009, the Participant generally may make such an election by January 30, 2010.

(3) A Participant made an election within 30 days of becoming eligible to participate in this Plan to receive his or her benefits in the form of a single life annuity under Section 6.2(b)(4). The Participant expects to retire June 30, 2012. At a reasonable time before the Determination Date, the Participant may make an election to receive an actuarially equivalent joint and survivor annuity, excluding any pop-up feature or level income option under the Retirement Plan.

6.4 Rehired Employees. An Employee whose employment is Terminated and then subsequently hired as an Employee of an Associated Company may become a Participant in this Plan and accrue a Supplemental Retirement Benefit attributable to the Employee's period of service after such rehire date only if and when the Employee thereafter becomes a Participant under Article III. The time and form of payment of any such rehired Participant will be governed by the elections of the Participant that had become effective with the Employer during his or her prior employment with the Employer, including elections made under the Central and South West System Special Executive

Retirement Plan or any other Plan sponsored by the Employer, but in no event will the benefit become payable earlier than the First Date Available.

6.5 Changes to Time and Form of Payment. A Participant will not be permitted to change the form of payment of his or her Supplemental Retirement Benefit unless (a) such election does not take effect until at least 12 months after the date on which the election is made, (b) in the case of an election related to payment not due to the Participant's Disability or death, the first payment with respect to which such new election is effective is deferred for a period of not less than five (5) years from the date such payment would otherwise have been made, and (c) any election related to a payment based upon a specific time or pursuant to a fixed schedule may not be made less than 12 months prior to the date of Termination; provided, however, that the selection of an annuity payment among actuarially equivalent annuity payments shall not be considered a change to the form of payment for purposes of applying the restrictions and clauses in Section 6.2 or 6.5.

Notwithstanding the preceding paragraph of this Section 6.5, a Participant may change an election with respect to the time and form of payment of a Supplemental Retirement Benefit, without regard to the restrictions imposed under the preceding paragraph, on or before December 31, 2008; provided that such election (a) applies only to amounts that would not otherwise be payable in the calendar year in which such election is made, and (b) shall not cause an amount to be paid in the calendar year in which the election is made that would not would otherwise be payable in such year.

6.6 Disability Payments. If a Participant incurs a disability that results in a Termination, the payment(s) of any accruals through such Termination will be governed by Section 6.2. A Participant who is receiving disability accruals under Section 4.5 after Termination shall receive payment of the Supplemental Retirement Benefits accrued after Termination in a lump sum as soon as practicable after the Maximum Disability Period.

6.7 Cash-Outs. Notwithstanding any election made under this Plan,

(a) if the Participant's Supplemental Retirement Benefit has a value of $10,000 or less on the Participant's First Date Available, the Committee may require that the full value of the Participant's Supplemental Retirement Benefit be distributed as of the First Date Available 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,

(b) 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.

ARTICLE VII
Death Benefits

7.1 Death of Participant Before Determination Date. Upon the death of a Participant prior to the Participant's Determination Date, the Participant's Beneficiary shall be entitled to a supplemental death benefit as follows:

(a) Calculation Methodology. Except as otherwise set forth herein, the death benefits payable under Section 7.1 of this Plan shall be calculated using the applicable methodology and subject to all limitations as provided in Article IV as of the first day of the month immediately following the Participant's death.

(b) Amount.

(1) If either (i) the Participant's Beneficiary is not his or her Spouse or (ii) the Participant's Supplemental Retirement Benefit does not take into account the Final Average Pay Formula under Section 4.3(a)(i), the amount of the benefit under this Section 7.1 is the amount equal to the excess (if any) of.

(a) The Unrestricted Benefit with respect to the Participant calculated using the Cash Balance Formula; over

(b) The Maximum Benefit with respect to the Participant calculated using the Cash Balance Formula.

(2) If both (i) the Participant's Beneficiary is his or her Spouse and (ii) the Participant's Supplemental Retirement Benefit takes into account the Final Average Pay Formula under Section 4.3(a)(i), the benefit under this Section 7.1 is the amount equal to the excess (if any) of:

(a) the greater of the Unrestricted Benefit with respect to the Participant calculated using the Cash Balance Formula or the pre-retirement survivor annuity calculated from the Unrestricted Benefit using the Final Average Pay Formula; over

(b) the greater of the Maximum Benefit with respect to the Participant calculated using the Cash Balance Formula or the pre-retirement survivor annuity calculated from the Maximum Benefit using the Final Average Pay Formula.

(c) Form. The death benefit under this Section 7.1 shall be paid in the same form applicable to the Participant in accordance with the provisions of Article VI as of the date of the Participant's death; provided to the extent that the distribution would be in the form of an annuity, the death benefit shall be paid to the Beneficiary in the form of a single life annuity.

(d) Timing. The death benefit under this Section 7.1 shall commence within 90 days after the Committee has made a final determination identifying the Participant's Beneficiary.

7.2 Death of Participant After the Determination Date. Upon the death of the Participant after the Determination Date, the Participant's Beneficiary or Beneficiaries shall receive the balance, if any, of the distributions payable under the form of distribution then in effect with respect to the Participant. If the Beneficiary is receiving benefits, the Beneficiary shall be entitled to designate a beneficiary for benefits payable upon the death of the Beneficiary.

7.3 Beneficiary Designation. Each Participant (or Beneficiary) may designate a Beneficiary or Beneficiaries who shall receive the benefits payable under this Plan following the death of the Participant. 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 designation form prescribed by the Committee. A beneficiary designation 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 the Committee receives a beneficiary designation form, any changes made on a form received thereafter will not be given any effect. If a Participant (or Beneficiary) fails to designate a Beneficiary, or if all Beneficiaries named by the Participant (or Beneficiary) do not survive the Participant (or Beneficiary), the Participant's (or Beneficiary's) benefit will be paid to the Participant's Beneficiary or Beneficiaries as determined under the terms of the Retirement Plan as of the date of the Participant's death, but no later than the latest benefit commencement date with respect to the Participant under the Retirement Plan. The designation by a Participant of the 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 unless a qualified domestic relations order that provides otherwise is received by the Committee a reasonable time before the benefits commence.

ARTICLE VIII
Administration

8.1 Authority of Committee. The Committee shall administer this Plan. The Committee shall have the full power, authority and discretion to interpret this Plan and to prescribe, amend and rescind rules and regulations relating to the administration of this Plan (including, but not limited to, procedures for submitting distribution election forms and the designation of beneficiaries), and all such interpretations, rules and regulations shall be conclusive and binding on all Participants.

8.2 Ability of Committee to Delegate Authority. The Committee may employ agents, attorneys, accountants, or other persons and allocate or delegate to them powers, rights, and duties all as the Committee determines, in its sole discretion, may be necessary or advisable to properly carry out the administration of this Plan.

ARTICLE IX
Amendment or Termination

9.1 Authority to Amend or Terminate Plan. The Company intends this Plan to be permanent but reserves the right to amend or terminate this Plan when, in the sole opinion of the Company, such amendment or termination is advisable. Any such amendment or termination shall be made in accordance with a resolution of the Board of Directors of the Company.

9.2 Limitations on Amendment and Termination Authority. No amendment or termination of this Plan shall directly or indirectly (a) deprive any current or former Participant or Beneficiary of all or any portion of any Supplemental Retirement Benefit which commenced prior to the effective date of such amendment or termination or (b) reduce any Participant’s Unrestricted Benefit that had accrued as of such effective date.

ARTICLE X
Change In Control

10.1 Vesting. Notwithstanding any provisions of the Plan to the contrary, if a Change in Control, as defined in Section 10.2, of the Corporation occurs, all Supplemental Retirement Benefits accrued as of the date of the Change in Control shall be fully vested and non-forfeitable.

10.2 Definition. A “Change in Control” of the Corporation shall be deemed to have occurred if and as of such date that (i) any “person” or “group” (as such terms are used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934 (“Exchange Act”)), other than any Corporation owned, directly or indirectly, by the shareholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation or a trustee or other fiduciary holding securities under any employee benefit plan of the Corporation, becomes “beneficial owner” (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of more than one-third (⅓) of the then outstanding voting stock of the Corporation; or (ii) the consummation of a merger or consolidation of the Corporation with any other entity, other than a merger or consolidation which would result in the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least two-thirds (⅔) of the total voting power represented by the voting securities of the Corporation or such surviving entity outstanding immediately after such merger or consolidation; or (iii) the consummation of the complete liquidation of the Corporation or the sale or disposition by the Corporation (in one transaction or a series of transactions) of all or substantially all of the Corporation’s assets.

For purposes of this Section 10.2, “Board” shall mean the Board of Directors of the Corporation, and “Director” shall mean an individual who is a member of the Board.

ARTICLE XI
Claims Procedure

11.1 Procedure for Submitting a Claim for Benefits. The following procedures shall apply with respect to claims for benefits under the Plan.

(a) Any 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 the amount calculated to be his or her Supplemental Retirement Benefit is inaccurate, may file a written claim signed by the Participant, Beneficiary or authorized representative with the Company's Director - Compensation and Executive Benefits, specifying the basis for the claim. The Director - Compensation and Executive Benefits 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 Director - Compensation and Executive Benefits 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 Director - Compensation and Executive Benefits renders an adverse benefit determination under Section 11.1(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 11.2, 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 ERISA, following an adverse benefit determination on review.

11.2 Procedure for Appealing an Adverse Benefit Determination. 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 Plan 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 XII
Miscellaneous

12.1 No Right of Employment. Nothing in this Plan shall interfere with or limit in any way the right of any Associated Company to terminate any Participant's employment at any time, nor confer upon a Participant any right to continue in the employ of the Associated Company.

12.2 Incompetence. 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, or is a minor, or has died, the Committee may direct that any payment due the Participant or the Beneficiary be paid, unless a prior claim shall have been made by a duly appointed legal representative, to the Participant's Spouse, a child, a parent or other blood relative, or to a person with whom the Participant resides, and any such payment so made shall be a complete discharge of the liabilities of the Plan and the Company and the Associated Company with respect to such Participant or Beneficiary.

12.3 Relationship with Retirement Plan. Except as otherwise expressly provided herein, all terms, conditions and actuarial assumptions of the Retirement Plan applicable to benefits payable under the terms of the Retirement Plan shall also be applicable to the Supplemental Retirement Benefits paid under the terms of the Plan.

12.4 Unsecured General Creditor. The Supplemental Retirement Benefits paid under the Plan shall not be funded, but shall constitute liabilities of the applicable Associated Company to be paid out of general corporate assets. Nothing contained in the Plan shall constitute a guaranty by any of the Associated Companies or any other entity or person that the assets of a particular Associated Company will be sufficient to pay any benefit hereunder. Participants and their Bene-ficiaries, heirs, successors and assigns shall have no legal or equitable rights, interests or claims in any property or assets of an Associated Company. For purposes of the payment of benefits under this Plan, any and all of an Associated Company's assets shall be, and remain, the general, unrestricted assets of the Associated Company. An Associated Company's obligation under the Plan shall be merely that of an unfunded and unsecured promise to pay money in the future.

12.5 Non-Assignability. 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; provided, however, that the Spouse's or former Spouse's benefit will be subject to the automatic cash-out provisions of Section 6.7 as a separate benefit.

12.6 Captions. The captions of the articles, sections and paragraphs of this Plan are for convenience only and shall not control or affect the meaning or construction of any of its provisions.

12.7 Governing Law. The Plan shall be construed and administered according to the applicable provisions of ERISA and the laws of the State of Ohio.

12.8 Validity. In case any provision of this Plan shall be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of this Plan. Instead, this Plan shall be construed and enforced as if such illegal or invalid provision had never been inserted herein.

12.9 Successors. The provisions of this Plan shall bind and inure to the benefit of the Participant's Employer and its successors and assigns and the Participant and the Participant's designated Beneficiaries.

12.10 Notice. Any notice or filing required or permitted to be given to the Committee under this Plan shall be sufficient if in writing and hand-delivered, or sent by registered or certified mail, to the address below:

American Electric Power Service Corporation
Attn: Executive Benefits
One Riverside Plaza
Columbus, Ohio 43215

Such notice shall be deemed given as of the date of delivery or, if delivery is made by mail, as of the date shown on the postmark on the receipt for registration or certification. Any notice or filing required or permitted to be given to a Participant under this Plan shall be sufficient if in writing and hand-delivered, or sent by mail, to the last known address of the Participant.

12.11 Tax Withholding. There shall be deducted from each payment made under this Plan or any other compensation payable to the Participant (or Beneficiary) all taxes that are required to be withheld by an Associated Company in respect to any payment under this Plan. The Associated Company shall have the right to reduce any payment (or compensation) by the amount of cash sufficient to provide the amount of such taxes.

IN WITNESS WHEREOF, the Company has caused this Plan to be signed by its authorized officer as of this 30th day of December, 2019.

AMERICAN ELECTRIC POWER
SERVICE CORPORATION

By: /s/ Tracy A. Elich
Tracy A. Elich,
Vice President - Human Resources

Exhibit 10(l)

CENTRAL AND SOUTH WEST SYSTEM
SPECIAL EXECUTIVE RETIREMENT PLAN

(As Amended and Restated Effective January 1, 2020)

ARTICLE I
Purposes and Effective Date

1.1 Purpose. The Central and South West System Special Executive Retirement Plan is an unfunded, nonqualified deferred compensation plan maintained to provide certain benefits for eligible employees whose retirement benefits from the Retirement Plan (as defined below) are restricted due to limitations imposed by provisions of the Internal Revenue Code or who are entitled to supplemental benefits under the terms of an employment agreement between the eligible employee and a Participating Employer.

1.2 Effective Date. The Plan originally was adopted by Central and South West Corporation in 1979. It later was amended and restated effective as of July 1, 1997 and January 1, 2009. This Plan is now amended and restated effective as of January 1, 2020, except as otherwise provided.

1.3 Plan Sponsor. Central and South West Corporation was the initial sponsor of the Plan. Central and South West Corporation later changed its name to AEP Utilities, Inc. December of 2016, AEP Utilities, Inc. was reorganized and changed its name to AEP Texas, Inc., and the responsibility for sponsorship of the Plan was transferred to American Electric Power Services Corporation, which was already then the Plan Administrator.

ARTICLE II
Definitions

The following terms shall have the meanings set forth in this Article II. Any undefined capitalized term in this Plan shall have the meaning set forth in the Retirement Plan.

2.1 "Accredited Service" means the period of time taken into account under the terms of the Retirement Plan for the purpose of computing a Retirement Plan benefit under the Final Average Pay Formula.

2.2 "Actuarial Equivalence" or "Actuarially Equivalent" will be determined using the assumptions and methods that are used in connection with the Cash Balance Formula under the Retirement Plan, regardless of whether the benefits under this Plan are determined under the Cash Balance Formula.

2.3 "Administrator" means American Electric Power Service Corporation.

2.4 "Base Compensation" means a Participant's regular base salary or base wage Earned through the date of the termination of employment of the Participant with the Participating Employers. Base Compensation shall be determined (i) without adjustment for any salary or wage elections made pursuant to Sections 125 (regarding cafeteria plans, including pre-tax contributions for premiums and flexible spending accounts) and 402(e)(3) (regarding elective deferrals, including before-tax contributions under a Section 401(k) retirement savings plan) of the Code, (ii) without reduction for any contributions to the Supplemental Savings Plan; and (iii) excluding bonuses (such as, but not limited to, project bonuses and sign-on bonuses), compensation paid pursuant to the terms of an annual compensation plan, performance pay awards, severance pay, relocation payments, or any other form of additional compensation that is not part of regular base salary or base wage.

2.5 "Beneficiary" means the person or entity designated in accordance with the provisions of Section 7.3, to receive the distribution of death benefits provided for in Article VII.

2.6 "Board of Directors" means the Board of Directors of the Company.

2.7 "Cash Balance Formula" means the formula under the Retirement Plan by which Participants accrue benefits through credits to his or her Cash Balance Account (as defined in the Retirement Plan). The Cash Balance Formula is effective beginning July 1, 1997.

2.8 "Cash Balance Unrestricted Benefit" means the Unrestricted Benefit calculated using the Cash Balance Formula.

2.9 "Code" means the Internal Revenue Code of 1986, as amended from time to time.

2.10 "Commissions" means a periodic incentive directly tied to an individual sale (including sales tied to a deal to which more than one individual is assigned) or quota achievement pursuant to a written and appropriately approved plan that is Earned during the relevant time period, but that is neither a team-based award nor a referral award nor other recognition award nor a part of the Participant's Base Compensation or Incentive Compensation.

2.11 "Committee" means the committee designated by the Administrator (or a person duly authorized to act on behalf of the Administrator) as responsible for the administration of the Plan.

2.12 "Company" means American Electric Power Service Corporation.

2.13 "Corporation" means American Electric Power Company, Inc., a New York corporation, and its affiliates and subsidiaries.

2.14 "Determination Date" means the first day of the month immediately following the Participant's Termination; provided, however, with respect to Participants who have already separated from service but have not yet received a distribution under the Plan as of December 1, 2008, the Determination Date shall be the date specified in accordance with Article VI for the commencement date for payment of his or her Special Retirement Benefit.

2.15 "Employee" means such persons employed by a Participating Employer who are designated in the records of the Participating Employer in a classification that is eligible to participate in the Retirement Plan.

2.16 "Employment Contract" means an agreement between a Participating Employer and an Employee that provides the Employee with a non-qualified retirement benefit attributable to this Plan.

2.17 "ERISA" means the Employee Retirement Income Security Act of 1974 as amended from time to time.

2.18 "First Date Available" or "FDA" means (a) with respect to a Participant who is a Key Employee as of the date of such Participant's Termination, the first day of the month next following the date that is six (6) months after the Participant's Termination; (b) with respect to Participants who have already separated from service but have not yet received a distribution under the Plan as of December 1, 2008, the date specified in accordance with Article VI for the commencement date for payment of his or her Special Retirement Benefit (or, if such Participant fails to specify such a date, January 1, 2009); and (c) with respect to all other Participants, the first day of the month next following the Participant's Termination.

2.19 "Grandfathered Participant" means a Participant who (i) is an employee of a Participating Employer on July 1, 1997, and (ii) has both attained age 50 and completed at least ten years of vesting service under the Retirement Plan on such date.

2.20 "HR Committee" means the Human Resources Committee of the board of directors of the Corporation (or any successor to such committee).

2.21 "Incentive Compensation" means incentive compensation Earned pursuant to the terms of an annual incentive compensation plan, provided that Incentive Compensation shall not include non-annual bonuses (such as but not limited to project bonuses and sign-on bonuses and amounts earned under a long-term incentive plan), severance pay, relocation payments, or any other form of additional compensation that is not considered to be part of Base Compensation.

2.22 "Key Employee" means a Participant who is classified as a "specified employee" at the time of Termination in accordance with policies adopted by 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.

2.23 "Maximum Benefit" means the vested retirement benefit payable from the Retirement Plan under either a Prior Plan Formula or the Cash Balance Formula, as provided in Article IV and Article V and as calculated based upon the Participant's marital status, Beneficiary, credited service, and earnings for services rendered to the Company, to the extent such are permitted by the Code and the Retirement Plan to be taken into account under the Final Average Pay Formula or the Cash Balance Formula, as applicable.

2.24 "Maximum Disability Period" means the last date any disability benefits may become payable under the terms of the American Electric Power System Long-Term Disability Plan in effect as of the later of December 31, 2008 or the last day on which the Participant's initial payment election may be made in accordance with Section 6.3.

2.25 "Next Date Available" or "NDA" means the July 1 of the calendar year immediately following the calendar year in which falls the Participant's Termination.

2.26 "Participant" means any exempt salaried Employee of a Participating Employer who has entered the Plan in accordance with Article III of this Plan and has accrued a benefit under the Plan.

2.27 "Participating Employer" means the Company and each subsidiary of the Corporation that is a participating employer under the Retirement Plan.

2.28 "Plan" means the Central and South West System Special Executive Retirement Plan, as amended and in effect from time to time.

2.29 "Plan Year" means the calendar year commencing each January 1 and ending each December 31.

2.30 "Premium Pay" means overtime pay and shift differential pay that is Earned during the relevant time period, but that is not a part of the Participant's Base Compensation or Incentive Compensation.

2.31 "Prior Plan Formula" means the Career Average Pay Formula or the Final Average Pay Formula under the Retirement Plan.

2.32 "Retirement Plan" means the Central and South West System Cash Balance Retirement Plan sponsored by the Company, as amended and restated effective July 1, 1997, and as further amended and in effect from time to time, which is a defined benefit pension plan intended to qualify under Section 401(a) of the Code.

2.33 "Special Retirement Benefit" means the basic retirement benefit determined under Article IV of this Plan.

2.34 "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).

2.35 "Unrestricted Benefit" means the vested retirement benefit that would be payable from the Retirement Plan under either a Prior Plan Formula or the Cash Balance Formula, as described in Article IV and Article V, assuming Sections 401(a)(17) (Compensation Limit) and 415 (Limitation on Benefits) of the Code are not applicable. The calculation of the Unrestricted Benefit also shall take into account other adjustments specified in an Employment Contract.

ARTICLE III
Participation in the Plan

3.1 Eligibility. All exempt salaried Employees of a Participating Employer shall be eligible to participate in this Plan so long as such Employee is either (A) entitled to a Special Retirement Benefit under the terms of an Employment Contract, or (B) both (1) a participant in the Retirement Plan, and (2) satisfies one of the following conditions below:

(a) The Employee's Base Compensation for the current or any prior Plan Year exceeds the limitation of Section 401(a)(17) of the Code,

(b) The Employee was a Participant in this Plan as of July 1, 1997,

(c) The Employee's Base Compensation plus Incentive Compensation plus Premium Pay for the current or any prior Plan Year (that ends on or after July 1, 1997, in that such amounts were taken into account for the calendar year 1997 in calculating the opening balance for Participants under the Cash Balance Formula) exceeds the limitation of Section 401(a)(17) of the Code; or

(d) The Employee's Base Compensation plus Incentive Compensation plus Commissions plus Premium Pay for the current or any prior Plan Year that begins on or after January 1, 2020 exceeds the limitation of Section 401(a)(17) of the Code.

All such eligibility determinations generally shall be made by December 31 of each year or such other time as set forth in an Employee Contract.

To further clarify, an Employee shall not be considered eligible to participate in this Plan unless such Employee has been continuously eligible to earn benefits under the Central and South West Corporation Cash Balance Retirement Plan since prior to January 1, 2001, the date that individuals hired or rehired by a Participating Employer would have instead become eligible to participate in the American Electric Power System Retirement Plan (as it existed prior to the merger of the Central and South West Corporation Cash Balance Retirement Plan with and into that plan effective December 31, 2008) and its related American Electric Power System Excess Benefit Plan.

3.2 Duration. An Employee who becomes a Participant shall continue to be a Participant until his or her Termination or the date he or she is no longer entitled to receive a Special Retirement Benefit under this Plan.

ARTICLE IV
Primary Benefit

4.1 General Benefits. Upon a Participant's Termination, the Participant shall be entitled to a Special Retirement Benefit calculated as of the Participant's Determination Date, as determined under this Article IV, to the extent vested, to be paid at the time and in the form determined in accordance with Article VI of this Plan. Except as otherwise specified in Article X, a Participant's Special Retirement Benefit shall become vested at the same time and to the same extent as may be provided under the terms of the Retirement Plan. Notwithstanding the foregoing, the amount, calculation methodology, or vesting of a Participant's Special Retirement Benefit may be reduced or otherwise modified in the manner described in an Employment Contract. Additionally, if the Committee determines that a Participant has incurred a liability to, or otherwise damaged, the Corporation, the Company or any Participating Employer, the Committee shall have the authority and power, in its sole discretion, to reduce any portion or all of the amounts that might otherwise become payable to such Participant under the terms of this Plan by the amount of such liability or damage, as reasonably determined by the Committee.

4.2 Calculation Methodology. For purposes of calculating the Special Retirement Benefit under Sections 4.3, 4.4 and 4.5 of this Plan, the following rules shall apply.

(a) To the extent a Participant's form of benefit under Article VI is a lump sum or installments, this calculation shall be based on the lump sum of the Unrestricted Benefit and Maximum Benefit. To the extent a Participant's form of benefit under Article VI is an annuity, this calculation shall be based on the single life annuity value of the Unrestricted Benefit and Maximum Benefit. If a Participant's form of benefit under Article VI is a combination lump sum distribution and life annuity [as set forth in Section 6.2(b)(5)], both calculations shall be made and the appropriate elected percentage applied to each.

(b) For purposes of calculating the Unrestricted Benefit using the Cash Balance Formula under Sections 4.3, 4.4, 4.5 and 5.2, and for purposes of calculating the Pension Equity Floor under Article V, effective for Compensation paid on or before December 31, 2019, annual Compensation taken into account shall be limited to the greater of $1,000,000 or 200% of the Participant's Base Compensation in effect on the last day of each applicable Plan Year (or if earlier, the date of Termination).

4.3 Amount of Benefit for Cash Balance Participants. A Participant in this Plan whose Retirement Plan benefit takes into account only the Cash Balance Formula shall be entitled to receive a benefit equal to the excess (if any) of the benefit calculated under paragraph (a) below over the benefit calculated under paragraph (b) below.

(a) The Unrestricted Benefit calculated using the Cash Balance Formula.

(b) The Maximum Benefit calculated using the Cash Balance Formula.

4.4 Benefits for Non-Grandfathered Prior Plan Formula Participants.

(a) Eligibility. If the following conditions are satisfied, a Participant shall receive the benefit described in Section 4.4 instead of the benefit calculated under Section 4.3.

(1) The Participant accrued a benefit under this Plan as of July 1, 1997; and

(2) The Participant is not a Grandfathered Participant.

(b) Amount of Benefit. The benefit under this Section 4.4 is equal to the excess, if any, of the benefit determined under paragraph (1) below over the benefit determined under paragraph (2) below:

(1) The greater of (a) the Unrestricted Benefit the Participant had accrued as of July 1, 1997, using the Prior Plan Formula, or (b) the Unrestricted Benefit calculated using the Cash Balance Formula.

(2) The greater of (a) the Maximum Benefit the Participant had accrued as of July 1, 1997, using the Prior Plan Formula, or (b) the Maximum Benefit calculated using the Cash Balance Formula.

4.5 Benefit for Grandfathered Participants.

(a) Eligibility. A Grandfathered Participant will receive the benefit in either Section 4.5(b) or 4.5(c) as applicable.

(b) Lump Sum or Installment Benefits. To the extent a Participant is to receive his or her benefits under this Plan in the form of a lump sum or installments, the benefit under this Section 4.5(b) is equal to the excess, if any, of the benefit determined under paragraph (1) below over the benefit determined under paragraph (2) below.

(1) The greater of (a) the Unrestricted Benefit calculated using the Prior Plan Formula, or (b) the Unrestricted Benefit calculated using the Cash Balance Formula.

(2) The greater of (a) the Maximum Benefit calculated using the Prior Plan Formula, or (b) the Maximum Benefit calculated using the Cash Balance Formula.

(c) Annuity Benefit. To the extent a Participant is to receive his or her benefits under this Plan in the form an annuity, the benefit under this Section 4.5 (c) is the annuity benefit described in paragraph (1) or (2) below, whichever has the greater Actuarially Equivalent value. Each annuity benefit will be valued at

Termination by comparing the annuity payable in the normal form under the Retirement Plan assuming that payments will commence on the Determination Date. The value of any annuity benefit payable that includes a cost of living adjustment shall be determined assuming that the future cost of living adjustments will be three percent (3%) per year.

(1) The excess, if any, of the Unrestricted Benefit calculated using the Prior Plan Formula over the Maximum Benefit calculated using the Prior Plan Formula.

(2) The excess, if any, of the Unrestricted Benefit calculated using the Cash Balance Formula over the Maximum Benefit calculated using the Cash Balance Formula.

4.6 Disability Accruals. Notwithstanding anything in the Plan to the contrary, if a Participant incurs a Disability (under the terms of the Retirement Plan), the Participant may continue to accrue a benefit under this Plan from the date of such Disability through the Maximum Disability Period to the extent the Participant is receiving such disability accruals under the Retirement Plan, as paid in accordance with Section 6.6.

ARTICLE V

Pension Equity Floor
(formerly called the "Final Average Pay Cash Balance Benefit")

5.1 Eligibility -- Cash Balance Participants. Only Participants who were identified as of May 31, 2000, to receive a Final Average Pay Cash Balance benefit are entitled to have the Pension Equity Floor calculation described in Section 5.2.

5.2. Potential Enhancement of Benefit. The "Pension Equity Floor" for an eligible Participant under Section 5.1 of this Plan shall be equal to the benefit that would be payable under the cash balance provisions of the Retirement Plan if:

(a) The Participant's Cash Balance Account were credited with an amount determined by multiplying (1) the Participant's highest average annual Base Compensation, Incentive Pay, and Premium Pay during any 36 consecutive calendar months in the 120 consecutive calendar months ending on the date of his or her Termination, by (2) the sum of the Participant's annual compensation contribution percentages under the Retirement Plan (beginning with the Plan Year for which the Participant is first allocated annual contribution credit), but

(b) without any interest credits under Retirement Plan, and

(c) to be determined before applying any provision reducing retirement benefits because of limitation on compensation under Section 401(a)(17) of the Code or the maximum benefit limitations under Section 415 of the Code.

If the Pension Equity Floor is greater than the Cash Balance Unrestricted Benefit, the Pension Equity Floor shall be substituted in place of the Cash Balance Unrestricted Benefit under Section 4.3, 4.4, or 4.5, as applicable.

ARTICLE VI
Payment of Vested Special Retirement Benefits

6.1 Determination of Special Retirement Benefit. Upon a Participant's Termination for any reason other than the Participant's death, the Participant's Special Retirement Benefit shall be calculated as of the Participant's Determination Date and, to the extent vested, distributed to the Participant in the manner described in Section 6.2. If the Special Retirement Benefit is payable in the form of a lump sum or installments, any unpaid balance shall be credited with interest at the Annual Interest Crediting Rate under the Retirement Plan from the Determination Date until the date of payment.

6.2 General Timing of Payment. A Participant generally is entitled to receive a Special Retirement Benefit upon Termination. Payment generally will be made at the following times and in the following forms, as specified in a Participant's Payment Election.

(a) Pre-2009 Distributions. If a payment is to be made or is to begin to be made before January 1, 2009, such benefits payable under the Plan will be paid or will begin at the same time as the Participant's benefit is paid or begins under the Retirement Plan. Such benefits also shall be payable in the same form as the Participant's benefit is to be paid under the Retirement Plan, unless the Participant made a valid election to otherwise change the form of payment in accordance with the rules and procedures adopted by the Committee from time to time to receive his or her Special Retirement Benefit in a lump sum payment.

(b) Post-2008 Distributions (other than to certain separated participants). If benefits are payable under the Plan on or after January 1, 2009 to a Participant other than a Participant who has already separated from service but has not yet received a distribution under the Plan prior to January 1, 2009, such benefits will be paid or will begin to be paid at such time and form elected by the Participant in accordance with the following distribution options:

(1) A single lump sum distribution

(a) as of the First Date Available; or

(b) as of the Next Date Available; or

(c) as of the fifth anniversary of the First Date Available; or

(d) as of the fifth anniversary of the Next Date Available; or

(2) In five (5) annual installments commencing

(a) as of the First Date Available; or

(b) as of the Next Date Available; or

(c) as of the fifth anniversary of the First Date Available; or

(d) as of the fifth anniversary of the Next Date Available; or

(3) In ten (10) annual installments commencing

(a) as of the First Date Available; or

(b) as of the Next Date Available; or

Effective for distribution elections or changes to distribution elections made on or after such date as the Committee shall designate:

(c) as of the fifth anniversary of the First Date Available; or

(d) as of the fifth anniversary of the Next Date Available; or

(4) As a single life annuity commencing on the First Date Available, or any Actuarially Equivalent "life annuity," (in accordance with Treasury Regulation 1.409A-2(b)(ii)) and as available as an annuity option under the Retirement Plan.

(5) A combination lump sum distribution and "life annuity" [as described in paragraph (b)(4), above] commencing as of the First Date Available, allocated in one of the following proportions:

(a) 25% as a lump sum distribution and 75% as a life annuity;

(b) 50% as a lump sum distribution and 50% as a life annuity; or

(c) 75% as a lump sum distribution and 25% as a life annuity.

(b) Post-2008 Distributions To Certain Separated Participants. If benefits are payable under the Plan on or after January 1, 2009 to a Participant who has already separated from service but has not yet received a distribution under the Plan prior to January 1, 2009, such benefits will be paid or will begin to be paid at such time and form elected by the Participant in accordance with the following distribution options:

(1) A single lump sum distribution

(a) as of January 1, 2009; or

(b) as of January 1, 2010; or

(c) as of January 1, 2011; or

(d) as of January 1, 2012; or

(e) as of January 1, 2013; or

(f) as of January 1, 2014;

(2) In five (5) annual installments commencing

(a) as of January 1, 2009; or

(b) as of January 1, 2010; or

(c) as of January 1, 2011; or

(d) as of January 1, 2012; or

(e) as of January 1, 2013; or

(f) as of January 1, 2014;

(3) In ten (10) annual installments commencing

(a) as of January 1, 2009; or

(b) as of January 1, 2010; or

(c) as of January 1, 2011; or

(d) as of January 1, 2012; or

(e) as of January 1, 2013; or

(f) as of January 1, 2014;

(4) As a single life annuity commencing on the First Date Available;

(5) As a joint and 50% survivor life annuity commencing on the First Date Available; or

(6) As a joint and 100% survivor life annuity commencing on the First Date Available.

(d) Key Employees. Notwithstanding the foregoing, with respect to any Participant who is a Key Employee, to the extent that any payments otherwise would have been made in the form of an annuity before the First Date Available, such payments shall be aggregated and paid on the First Date Available.

6.3 Participant Elections. Each Participant in the Plan may make an election as to the time and form of payment of his or her Special Retirement Benefit, as provided in Section 6.2. Participants must make such an election in accordance with the following deadlines.

(a) Generally. Except as otherwise provided in this Plan, a Participant must make his or her payment election by December 31 of the calendar year before the calendar year in which he or she first becomes a Participant in this Plan.

(b) Newly Eligible Participants. If an individual first becomes a Participant during a calendar year, 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 under Section 409A of the Code, the Participant may make an election by no later than the 30^{th} day after becoming a Participant in the Plan.

(c) Excess Benefit Plan Participants. If an individual first becomes a Participant on or after January 1, 2008, and participation in this Plan is considered participation in an "excess benefit plan," the Participant may make an election no later than the 30^{th} day after the last day of the first calendar year in which the Participant satisfied the requirements to become a Participant, provided that such individual has neither an accrued benefit nor been allocated any deferral under any other excess benefit plan. For this purpose, the term "excess benefit plan" means all nonqualified deferred compensation plans in which the individual participates, to the extent such plans do not provide for an election between the current compensation and deferred compensation and solely provide deferred compensation equal to the excess of the benefits the individual would have accrued under a qualified employer plan in which the individual also participates, in the absence of one or more of the limits incorporated into the plan to reflect one or more of the limits on contributions or benefits applicable to the qualified employer plan under the Code, over the benefits the individual actually accrues under the qualified employer plan, as described in Treasury Regulation Section 1.409A-2(a)(7)(iii).

(d) Actuarially Equivalent Life Annuities. A Participant who elected an annuity option described in Section 6.2(b)(4) or (5) of this Plan may make an irrevocable election within 60 days after the Determination Date to receive his or her benefits in the form of any other annuity option available under Section 6.2(b)(4) or (5) of this Plan. If the Participant fails to make a timely election as to the form of annuity, the Participant shall be deemed to have selected a 100% joint and survivor annuity with the Participant's Beneficiary as the survivor annuitant.

(e) Default. If a Participant fails to make an initial payment election in the times provided in this Section 6.3, the Participant shall be deemed to have elected to receive payment of his or her Special Retirement Benefit in a lump sum on the First Date Available.

(f) Examples.

(1) If an individual's Employment Contract is effective May 31, 2009, and the Employment Contract provides that the Participant will receive a Special Retirement Benefit in a manner that causes this Plan not to be considered an excess benefit plan for that Participant, the Participant must make a payment election by June 30, 2009.

(2) If an Employee is designated a Participant in 2009 because his or her compensation exceeded the limit under Section 401(a)(17) of the Code as of October 31, 2009, the Participant generally may make such an election by January 30, 2010.

(3) A Participant made an election within 30 days of becoming eligible to participate in this Plan to receive his or her benefits in the form of a single life annuity under Section 6.2(b)(4). The Participant expects to retire June 30, 2012. At a reasonable time before the Determination Date, the Participant may make an election to receive an Actuarially Equivalent joint and survivor annuity under the Retirement Plan.

6.4 Rehired Employees. An Employee whose employment is Terminated and then subsequently hired as an Employee of a Participating Employer after January 1, 2001, may not become an active Participant in the Plan with respect to compensation earned or service after such prior Termination.

6.5 Changes to Time and Form of Payment. A Participant will not be permitted to change the form of payment of his or her Special Retirement Benefit unless (a) such election does not take effect until at least 12 months after the date on which the election is made, (b) in the case of an election related to payment not due to the Participant's Disability or death, the first payment with respect to which such new election is effective is deferred for a period of not less than five (5) years from the date such payment would otherwise have been made, and (c) any election related to a payment based upon a specific time or pursuant to a fixed schedule may not be made less than 12 months prior to the date of Termination; provided, however, that an election to change from one type of annuity payment to a different, Actuarially Equivalent type of annuity payment shall not be considered a change to the form of payment for purposes of applying the restrictions and clauses (a), (b) and (c).

Notwithstanding the preceding paragraph of this Section 6.5, a Participant may change an election with respect to the time and form of payment of a Special Retirement Benefit, without regard to the restrictions imposed under the preceding paragraph, on or before December 31, 2008; provided that such election (a) applies only to amounts that would not otherwise be payable in the calendar year in which such election is made, and (b) shall not cause an amount to be paid in the calendar year in which the election is made that would not would otherwise be payable in such year.

6.6 Disability Payments. If a Participant incurs a Disability that results in a Termination, the payment(s) of any accruals through such Termination will be governed by Section 6.2. A Participant who is receiving Disability accruals under Section 4.6 after Termination shall receive payment of the Supplemental Retirement Benefits accrued after Termination in a lump sum as soon as practicable after the Maximum Disability Period.

6.7 Cash-Outs. Notwithstanding any election made under this Plan,

(a) if the Participant's Special Retirement Benefit has a value of $10,000 or less on the Participant's First Date Available, the Committee may require that the full value of the Participant's Special Retirement Benefit be distributed as of the First Date Available 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,

(b) 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.

ARTICLE VII
Death Benefits

7.1 Death of Participant Before Determination Date. Upon the death of a Participant prior to the Participant's Determination Date, the Participant's Beneficiary shall be entitled to a deceased Participant's Special Retirement Benefit under Article IV or Article V, whichever is applicable, as follows:

(a) Calculation Methodology. Except as otherwise set forth herein, the death benefits payable under Section 7.1 of this Plan shall be calculated using the applicable methodology and subject to all limitations as provided in Article IV (including as to the applicability of plan formulas, compensation taken into account as of the first day of the month immediately following the Participant's death.

(b) Amount.

(1) If either (i) the Participant's Beneficiary is not his or her Spouse or (ii) the Participant's Supplemental Retirement Benefit does not take into account the Prior Plan Formula under Section 4.4 or 4.5, the amount of the benefit under this Section 7.1 is the amount equal to the excess (if any) of:

(a) The Unrestricted Benefit with respect to the Participant calculated using the Cash Balance Formula; over

(b) The Maximum Benefit with respect to the Participant calculated using the Cash Balance Formula.

(2) If (i) the Participant's Beneficiary is his or her Spouse and (ii) the Participant's Supplemental Retirement Benefit is determined under Section 4.4, the benefit under this Section 7.1 is the amount equal to the excess (if any) of:

(a) the greater of (1) the Unrestricted Benefit with respect to the Participant calculated using the Cash Balance Formula or (2) the pre-retirement survivor annuity calculated from the Unrestricted Benefit the Participant had accrued as of July 1, 1997 using the Prior Plan Formula; over

(b) the greater of (1) the Maximum Benefit with respect to the Participant calculated using the Cash Balance Formula or (2) the pre-retirement survivor annuity calculated from the Maximum Benefit the Participant had accrued as of July 1, 1997 using the Final Average Pay Formula.

(3) If (i) the Participant's Beneficiary is his or her Spouse and (ii) the Participant's Supplemental Retirement Benefit is determined under Section 4.5(b), the benefit under this Section 7.1 is the amount equal to the excess (if any) of:

(a) the greater of (1) the Unrestricted Benefit with respect to the Participant calculated using the Cash Balance Formula or (2) the pre-retirement survivor annuity calculated from the Unrestricted Benefit using the Prior Plan Formula; over

(b) the greater of (1) the Maximum Benefit with respect to the Participant calculated using the Cash Balance Formula or (2) the pre-retirement survivor annuity calculated from the Maximum Benefit using the Final Average Pay Formula.

(4) If (i) the Participant's Beneficiary is his or her Spouse and (ii) the Participant's Supplemental Retirement Benefit is determined under Section 4.5(c), the benefit under this Section 7.1 is the annuity benefit described in paragraph (a) or (b) below, whichever has the greater Actuarially Equivalent value. Each annuity benefit will be valued at the date of the Participant's death by comparing the survivor annuity payable in the normal form under the Retirement Plan assuming that payments will commence on the first day of the month immediately following the Participant's death. The value of any annuity benefit payable that includes a cost of living adjustment shall be determined assuming that the future cost of living adjustments will be three percent (3%) per year.

(a) The excess, if any, of the pre-retirement survivor annuity calculated from the Unrestricted Benefit calculated using the Prior Plan Formula over the pre-retirement survivor annuity calculated from the Maximum Benefit calculated using the Prior Plan Formula.

(b) The excess, if any, of the Unrestricted Benefit calculated using the Cash Balance Formula over the Maximum Benefit calculated using the Cash Balance Formula.

(c) Form. The death benefit under this Section 7.1 shall be paid in the same form applicable to the Participant in accordance with the provisions of Article VI as of the date of the Participant's death; provided to the extent the distribution would be in the form of an annuity, the death benefit shall be paid to the Beneficiary in the form of a single life annuity.

(d) Timing. The death benefit under this Section 7.1 shall commence within 90 days after the Committee has made a final determination identifying the Participant's Beneficiary.

7.2 Death of Participant After the Determination Date. Upon the death of the Participant after the Determination Date, the Participant's Beneficiary or Beneficiaries shall receive the balance, if any, of the distributions payable under the form of distribution then in effect with respect to the Participant. If the Beneficiary is receiving benefits, the Beneficiary shall be entitled to designate a beneficiary for benefits payable upon the death of the Beneficiary.

7.3 Beneficiary Designation. Each Participant (or Beneficiary) may designate a Beneficiary or Beneficiaries who shall receive the benefits payable under this Plan following the death of the Participant. 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 designation form prescribed by the Committee. A beneficiary designation 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 the Committee receives a beneficiary designation form, any changes made on a form received thereafter will not be given any effect. If a Participant (or Beneficiary) fails to designate a Beneficiary, or if all Beneficiaries named by the Participant (or Beneficiary) do not survive the Participant (or Beneficiary), the Participant's (or Beneficiary's) benefit will be paid to the Participant's Beneficiary or Beneficiaries as determined under the terms of the Retirement Plan as of the date of the Participant's death, but no later than the latest benefit commencement date with respect to the Participant under the Retirement Plan. The designation by a Participant of the 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 unless a qualified domestic relations order that provides otherwise is received by the Committee a reasonable time before the benefits commence.

ARTICLE VIII
Administration

8.1 Authority of Committee. The Committee shall administer this Plan. The Committee shall have the full power, authority and discretion to interpret this Plan and to prescribe, amend and rescind rules and regulations relating to the administration of this Plan (including, but not limited to, procedures for submitting distribution election forms and the designation of beneficiaries), and all such interpretations, rules and regulations shall be conclusive and binding on all Participants.

8.2 Ability of Committee to Delegate Authority. The Committee may employ agents, attorneys, accountants, or other persons and allocate or delegate to them powers, rights, and duties all as the Committee determines, in its sole discretion, may be necessary or advisable to properly carry out the administration of this Plan.

ARTICLE IX
Amendment or Termination

9.1 Authority to Amend or Terminate Plan. The Company intends this Plan to be permanent but reserves the right to amend or terminate this Plan when, in the sole opinion of the Company, such amendment or termination is advisable. Any such amendment or termination shall be made in accordance with a resolution of the Board of Directors of the Company.

9.2 Limitations on Amendment and Termination Authority. No amendment or termination of this Plan shall directly or indirectly (a) deprive any current or former Participant or Beneficiary of all or any portion of any Special Retirement Benefit which commenced prior to the effective date of such amendment or termination or (b) reduce any Participant's Unrestricted Benefit that had accrued as of such effective date.

ARTICLE X
Change In Control

10.1 Vesting. Notwithstanding any provisions of the Plan to the contrary, if a Change in Control, as defined in Section 10.2, of the Corporation occurs, all Special Retirement Benefits accrued as of the date of the Change in Control shall be fully vested and non-forfeitable.

10.2 Definition. A "Change in Control" of the Corporation shall be deemed to have occurred if and as of such date that (i) any "person" or "group" (as such terms are used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934 ("Exchange Act")), other than any Corporation owned, directly or indirectly, by the shareholders of the Corporation in substantially the same proportions as their ownership of stock of the Corporation or a trustee or other fiduciary holding securities under any employee benefit plan of the Corporation, becomes "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of more than one-third (⅓) of the then outstanding voting stock of the Corporation; or (ii) the consummation of a merger or consolidation of the Corporation with any other entity, other than a merger or consolidation which would result in the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least two-thirds (⅔) of the total voting power represented by the voting securities of the Corporation or such surviving entity outstanding immediately after such merger or consolidation; or (iii) the consummation of the complete liquidation of the Corporation or the sale or disposition by the Corporation (in one transaction or a series of transactions) of all or substantially all of the Corporation's assets.

For purposes of this Section 10.2, "Board" shall mean the Board of Directors of the Corporation, and "Director" shall mean an individual who is a member of the Board.

ARTICLE XI
Claims Procedure

11.1 Procedure for Submitting a Claim for Benefits. The following procedures shall apply with respect to claims for benefits under the Plan.

(a) Any 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 the amount calculated to be his or her Special Retirement Benefit is inaccurate, may file a written claim signed by the Participant, Beneficiary or authorized representative with the Administrator's Director - Compensation and Executive Benefits, specifying the basis for the claim. The Director - Compensation and Executive Benefits 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 Director - Compensation and Executive Benefits 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 Director - Compensation and Executive Benefits renders an adverse benefit determination under Section 11.1(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 11.2, 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.

11.2 Procedure for Appealing an Adverse Benefit Determination. 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 Plan 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 XII
Miscellaneous

12.1 No Right of Employment. Nothing in this Plan shall interfere with or limit in any way the right of the Company to terminate any Participant's employment at any time, nor confer upon a Participant any right to continue in the employ of the Company.

12.2 Incompetence. 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, or is a minor, or has died, the Committee may direct that any payment due the Participant or the Beneficiary be paid, unless a prior claim shall have been made by a duly appointed legal representative, to the Participant's Spouse, a child, a parent or other blood relative, or to a person with whom the Participant resides, and any such payment so made shall be a complete discharge of the liabilities of the Plan and the Company and the Participating Employer with respect to such Participant or Beneficiary.

12.3 Relationship with Retirement Plan. Except as otherwise expressly provided herein, all terms, conditions and actuarial assumptions of the Retirement Plan applicable to benefits payable under the terms of the Retirement Plan shall also be applicable to the Special Retirement Benefits paid under the terms of the Plan.

12.4 Unsecured General Creditor. The Special Retirement Benefits paid under the Plan shall not be funded, but shall constitute liabilities of the Participating Employers to be paid out of general corporate assets. Nothing contained in the Plan shall constitute a guaranty by the Participating Employers or any other entity or person that the assets of a particular Participating Employer will be sufficient to pay any benefit hereunder. Participants and their Bene-ficiaries, heirs, successors and assigns shall have no legal or equitable rights, interests or claims in any property or assets of a Participating Employer. For purposes of the payment of benefits under this Plan, any and all of a Participating Employer's assets shall be, and remain, the general, unrestricted assets of the Participating Employer. A Participating Employer's obligation under the Plan shall be merely that of an unfunded and unsecured promise to pay money in the future.

12.5 Non-Assignability. 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; provided, however, that the Spouse’s or former Spouse’s benefit will be subject to the automatic cash-out provisions of Section 6.7 as a separate benefit.

12.6 Captions. The captions of the articles, sections and paragraphs of this Plan are for convenience only and shall not control or affect the meaning or construction of any of its provisions.

12.7 Governing Law. The Plan shall be construed and administered according to the applicable provisions of ERISA and the laws of the State of Ohio.

12.8 Validity. In case any provision of this Plan shall be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of this Plan. Instead, this Plan shall be construed and enforced as if such illegal or invalid provision had never been inserted herein.

12.9 Successors. The provisions of this Plan shall bind and inure to the benefit of the Participant's Employer and its successors and assigns and the Participant and the Participant's designated Beneficiaries.

12.10 Notice. Any notice or filing required or permitted to be given to the Committee under this Plan shall be sufficient if in writing and hand-delivered, or sent by registered or certified mail, to the address below:

American Electric Power Service Corporation
Attn: Executive Benefits
One Riverside Plaza
Columbus, Ohio 43215

Such notice shall be deemed given as of the date of delivery or, if delivery is made by mail, as of the date shown on the postmark on the receipt for registration or certification. Any notice or filing required or permitted to be given to a Participant under this Plan shall be sufficient if in writing and hand-delivered, or sent by mail, to the last known address of the Participant.

12.11 Tax Withholding. There shall be deducted from each payment made under this Plan or any other compensation payable to the Participant (or Beneficiary) all taxes that are required to be withheld by the Company in respect to any payment under this Plan. The Company shall have the right to reduce any payment (or compensation) by the amount of cash sufficient to provide the amount of such taxes.

Executed at Columbus, Ohio this 30th day of December, 2019.

American Electric Power Service Corporation

By: /s/ Tracy A. Elich
Tracy A. Elich, Vice President - Human
Resources for the AEP System

2019 Annual Reports

American Electric Power Company, Inc. and Subsidiary Companies

AEP Texas Inc. and Subsidiaries

AEP Transmission Company, LLC and Subsidiaries

Appalachian Power Company and Subsidiaries

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Audited Financial Statements and
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AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEP Utilities	AEP Utilities, Inc., a former subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. Effective December 31, 2016, TCC and TNC were merged into AEP Utilities, Inc. Subsequently following this merger, the assets and liabilities of CSW Energy, Inc. were transferred to a competitive affiliate company and AEP Utilities, Inc. was renamed AEP Texas Inc.
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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in deregulated markets.
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 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 variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
APSC	Arkansas Public Service Commission.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for ratemaking purposes.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Conesville Plant	A single unit coal-fired generation plant totaling 651 MW located in Conesville, Ohio. The plant is jointly owned by AGR and a nonaffiliate.

Term	Meaning
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,288 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSAPR	Cross-State Air Pollution Rule.
CWA	Clean Water Act.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel IX, DCC Fuel X, DCC Fuel XI, DCC Fuel XII, DCC Fuel XIII, and DCC Fuel XIV consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DOE	U. S. Department of Energy.
Desert Sky	Desert Sky Wind Farm, a 168 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
DIR	Distribution Investment Rider.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Cost.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
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.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
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 FAC Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxics Standards.

Term	Meaning
MISO	Midwest Independent Transmission 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.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
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.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
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.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
Price River	Rights and interests in certain coal reserves located in Carbon County, Utah.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
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 48 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.
REP	Texas Retail Electric Provider.
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.

Term	Meaning
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.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
Santa Rita East	Santa Rita East Wind Holdings, LLC, a consolidated VIE whose sole purpose is to own and operate a 302 MW wind generation facility in west Texas in which AEP owns a 75% interest.
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.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, each of which is geographically aligned with AEP existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
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.
TNC	Formerly AEP Texas North Company, now a division of AEP 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 variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Trent	Trent Wind Farm, a 154 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UMWA	United Mine Workers of America.
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.

Term	Meaning
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project that was cancelled in July 2018. The estimated $4.5 billion project included the acquisition of a wind generation facility, totaling approximately 2,000 MWs 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," 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.

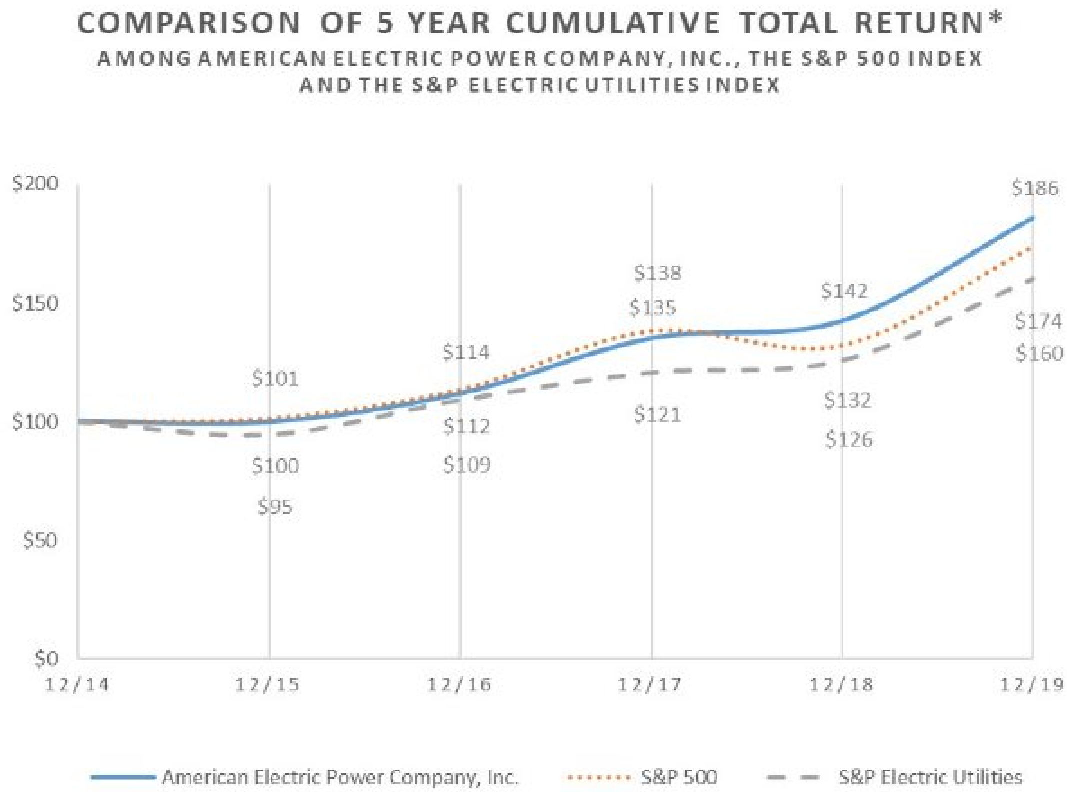
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber security threats and other catastrophic events.
- The ability to attract and retain the requisite work force and key personnel.

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, except as required by law. For a more detailed discussion of these factors, see "Risk Factors" in Part I of this report.

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

AEP COMMON STOCK INFORMATION

AEP common stock is principally traded using the trading symbol "AEP" on the New York Stock Exchange. As of December 31, 2019, AEP had approximately 57,000 registered shareholders.



*$100 invested on 12/31/14 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

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

	2019 (a)	2018	2017	2016	2015
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 15,561.4	$ 16,195.7	$ 15,424.9	$ 16,380.1	$ 16,453.2
Operating Income	$ 2,592.3	$ 2,682.7	$ 3,525.0	$ 1,163.9	$ 3,292.4
Income from Continuing Operations	$ 1,919.8	$ 1,931.3	$ 1,928.9	$ 620.5	$ 1,768.6
Income (Loss) From Discontinued Operations, Net of Tax	—	—	—	(2.5)	283.7
Net Income	1,919.8	1,931.3	1,928.9	618.0	2,052.3
Net Income (Loss) Attributable to Noncontrolling Interest	(1.3)	7.5	16.3	7.1	5.2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,921.1	$ 1,923.8	$ 1,912.6	$ 610.9	$ 2,047.1
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 79,145.7	$ 73,085.2	$ 67,428.5	$ 62,036.6	$ 65,481.4
Accumulated Depreciation and Amortization	19,007.6	17,986.1	17,167.0	16,397.3	19,348.2
Total Property, Plant and Equipment – Net	$ 60,138.1	$ 55,099.1	$ 50,261.5	$ 45,639.3	$ 46,133.2
Total Assets	$ 75,892.3	$ 68,802.8	$ 64,729.1	$ 63,467.7	$ 61,683.1
Total AEP Common Shareholders’ Equity	$ 19,632.2	$ 19,028.4	$ 18,287.0	$ 17,397.0	$ 17,891.7
Noncontrolling Interests	$ 281.0	$ 31.0	$ 26.6	$ 23.1	$ 13.2
Long-term Debt (b)	$ 26,725.5	$ 23,346.7	$ 21,173.3	$ 20,256.4	$ 19,572.7
Obligations Under Finance Leases (b)	$ 306.8	$ 289.0	$ 297.8	$ 305.5	$ 343.5
Obligations Under Operating Leases (b) (c)	$ 968.7	$ —	$ —	$ —	$ —
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
From Continuing Operations	$ 3.89	$ 3.90	$ 3.89	$ 1.25	$ 3.59
From Discontinued Operations	—	—	—	(0.01)	0.58
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 3.89	$ 3.90	$ 3.89	$ 1.24	$ 4.17
Weighted Average Number of Basic Shares Outstanding (in millions)	493.7	492.8	491.8	491.5	490.3
Market Price Range:					
High	$ 96.22	$ 81.05	$ 78.07	$ 71.32	$ 65.38
Low	$ 72.26	$ 62.71	$ 61.82	$ 56.75	$ 52.29
Year-end Market Price	$ 94.51	$ 74.74	$ 73.57	$ 62.96	$ 58.27
Cash Dividends Declared per AEP Common Share	$ 2.71	$ 2.53	$ 2.39	$ 2.27	$ 2.15

Dividend Payout Ratio		69.67%		64.87%		61.44%		183.06%		51.56%
Book Value per AEP Common Share	$	39.73	$	38.58	$	37.17	$	35.38	$	36.44

(a) The 2019 financial results include pretax asset impairments of $156 million. See Note 7 - Acquisitions, Dispositions and Impairments for additional information.
(b) Includes portion due within one year.
(c) Reflects the adoption of ASU 2016-02 “Accounting for Leases.” See Note 2 - New Accounting Standards and Note 13 - Leases for additional information.

EXECUTIVE OVERVIEW

Company Overview

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

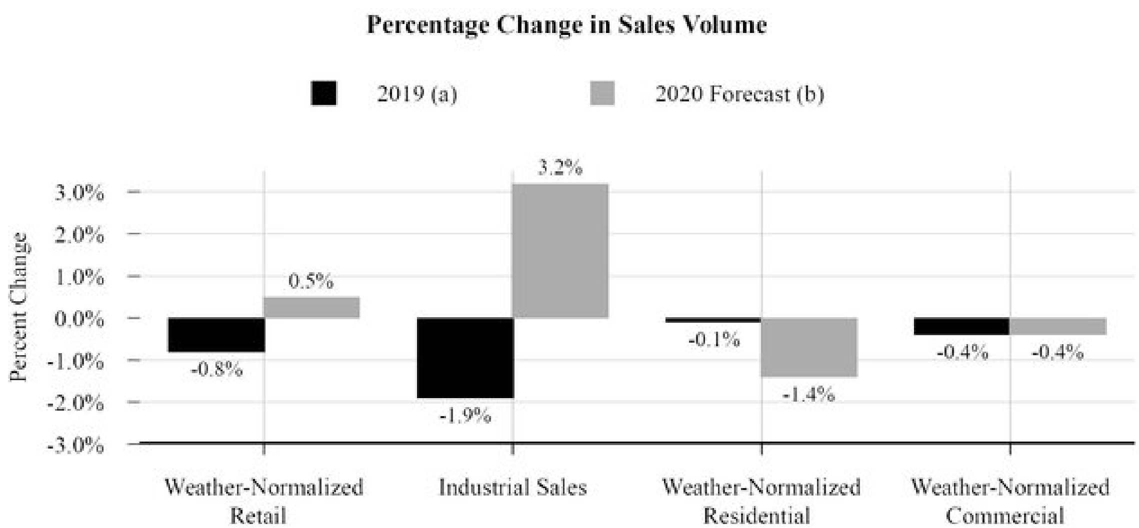
AEP's subsidiaries operate an extensive portfolio of assets including:

- Approximately 221,000 miles of distribution lines that deliver electricity to 5.5 million customers.
- Approximately 40,000 circuit miles of transmission lines, including approximately 2,200 circuit miles of 765 kV lines, the backbone of the electric interconnection grid in the eastern United States.
- Approximately 22,000 MWs of regulated owned generating capacity and approximately 4,900 MWs of regulated PPA capacity in 3 RTOs as of December 31, 2019, one of the largest complements of generation in the United States.

Customer Demand

AEP's weather-normalized retail sales volumes for the year ended December 31, 2019 decreased by 0.8% from the year ended December 31, 2018. AEP's 2019 industrial sales volumes decreased 1.9% compared to 2018. The decline in industrial sales was spread across most operating companies and many industries. Weather-normalized residential sales decreased 0.1% despite a 0.3% growth in customer counts. Weather-normalized commercial sales decreased by 0.4% in 2019 compared to 2018.

In 2020, AEP anticipates weather-normalized retail sales volumes will increase by 0.5%. The industrial class is expected to increase by 3.2% in 2020, while weather-normalized residential sales volumes are projected to decrease by 1.4%. Weather-normalized commercial sales volumes are projected to decrease by 0.4%.



(a) Percentage change for the year ended December 31, 2019 as compared to the year ended December 31, 2018.
(b) Forecasted percentage change for the year ended December 31, 2020 compared to the year ended December 31, 2019.

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.

- *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. In November 2019, ALJs issued a Proposal for Decision recommending a $60 million annual rate reduction based upon a 9.4% return on common equity. The ALJs recommended disallowances that could potentially result in write-offs of $84 million related to capital incentives and $5 million related to other plant additions. Additionally, the ALJs recommended that AEP Texas should be required to file an application for a separate proceeding to determine if any refunds are required associated with any disallowances on distribution or transmission capital investments. In February 2020, AEP Texas, the PUCT staff and various intervenors filed a stipulation and settlement agreement with the PUCT. The agreement includes a proposed annual base rate reduction of $40 million based upon a 9.4% return on common equity with a capital structure of 57.5% debt and 42.5% common equity. The agreement provides recovery of $26 million in capitalized vegetation management expenses that were incurred through 2018. The agreement includes disallowances of $23 million related to capital investments recorded through 2018 and $4 million related to rate case expenses. In addition, AEP Texas will refund: (a) $77 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to distribution customers over a one year period, (b) $31 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to transmission customers as a one-time credit and (c) $30 million of previously collected rates that were subject to reconciliation in this proceeding over a one year period with no carrying costs. As a result of the stipulation and settlement agreement, AEP Texas (a) recorded an impairment of $33 million in December 2019 related to capital investments, which included $10 million of current year investments, (b) recorded a $30 million provision for refund for revenues previously collected through rates and (c) wrote-off $4 million of rate case expenses. The PUCT is expected to issue an order in the first quarter of 2020.

- *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. In August 2019, certain 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 if I&M is approved to deploy Automated Metering Infrastructure meters and $11 million associated with certain Cook Plant study costs. The IURC is expected to issue an order on this case in 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 in excess of 70 basis points above APCo's Virginia SCC authorized ROE would be refunded to customers. Virginia law provides that costs associated with asset impairments of retired coal generation assets, or automated meters, or both, which a utility records as an expense, shall be attributed to the test periods under review in a triennial review proceeding, and be deemed recovered. Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets in December 2019. This expense is included in Asset Impairments and Other Related Charges on the statements of income. As a result, management deems these costs to be substantially recovered by APCo during the triennial review period. Inclusive of the $93 million expense associated with APCo's Virginia jurisdictional retired coal-fired plants, APCo estimates its Virginia earnings for the triennial period to be below the authorized ROE range.

- *2020 Increase in West Virginia Retail Rates for WPCo 17.5% Merchant Share of Mitchell Plant* - In 2015, the WVPSC approved a settlement agreement in which 82.5% of the West Virginia jurisdictional 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 to reflect the recovery of WPCo's remaining 17.5% interest in the Mitchell Plant. In December 2019, the WVPSC issued an order approving a stipulation and settlement agreement that will allow APCo and WPCo to recover the remaining 17.5% West Virginia share of costs related to the Mitchell Plant and increase pretax earnings on a combined company basis by approximately $21 million annually beginning January 1, 2020.

- *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 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. In the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court. As of December 31, 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 including lost shared savings revenues of $26 million annually 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
SWEPCo	Arkansas	52.8	9.45%	January 2020
I&M	Michigan	36.4	9.86%	February 2020

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase	Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE
			(in millions)		
AEP Texas (a)	Texas	May 2019	$ 56.0	10.5%	9% - 9.35%
I&M	Indiana	May 2019	172.0	10.5%	9% - 9.73%

(a) In February 2020, AEP Texas, the PUCT staff and various intervenors filed a stipulation and settlement agreement with the PUCT that includes a proposed annual base rate reduction of $40 million based upon a 9.4% return on common equity. See “2019 Texas Base Rate Case” section of Note 4 for additional information.

Dolet Hills Power Station and Related Fuel Operations

During the second quarter of 2019, the Dolet Hills Power Station initiated a seasonal operating schedule. In January 2020, in accordance with the terms of SWEPCo’s settlement of its base rate review filed with the APSC, management announced that SWEPCo will seek regulatory approval to retire the Dolet Hills Power Station by the end of 2026. Management also continues to monitor the economic viability of the Dolet Hills Power Station and DHLC mining operations, which may result in a decision to seek permission from appropriate regulatory agencies to discontinue operations earlier than 2026.

The Dolet Hills Power Station costs are recoverable by SWEPCo through base rates. SWEPCo’s share of the net investment in the Dolet Hills Power Station is $157 million, including CWIP and materials and supplies, before cost of removal.

Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses. Under the Lignite Mining Agreement, DHLC bills SWEPCo its proportionate share of incurred lignite extraction and associated mining-related costs as fuel is delivered. As of December 31, 2019, DHLC has unbilled fixed costs of $106 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. In 2009, SWEPCo acquired interests in the Oxbow Lignite Company (Oxbow), which owns mineral rights and leases land. Under a Joint Operating Agreement pertaining to the Oxbow mineral rights and land leases, Oxbow bills SWEPCo its proportionate share of incurred costs. As of December 31, 2019, Oxbow has unbilled fixed costs of $22 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. Additional operational and land-related costs are expected to be incurred by DHLC and Oxbow and billed to SWEPCo prior to the closure of the Dolet Hills Power Station and recovered through fuel clauses.

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

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 $580 million in cash and acquired a 50% ownership interest in five non-consolidated joint ventures with net assets valued at $404 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 7 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 7 for additional information.

As of December 31, 2019, subsidiaries within AEP's Generation & Marketing segment had approximately 1,421 MWs of contracted renewable generation projects in-service. In addition, as of December 31, 2019, these subsidiaries had approximately 156 MWs of renewable generation projects under construction with total estimated capital costs of $229 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. In November 2019, PUCO denied OPCo's application for a resource planning need finding. In December 2019, OPCo filed an Application for Rehearing, which was also denied.

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 54.5% 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. In December 2019, PSO reached a joint stipulation and settlement agreement with the OCC, Oklahoma Attorney General's office and customer groups. In January 2020, SWEPCo reached a joint settlement agreement with the APSC, Arkansas Attorney General's office and Walmart, Inc. SWEPCo continues to work through the regulatory process in Texas and Louisiana. Hearings are scheduled for the first quarter of 2020. PSO and SWEPCo are seeking regulatory approvals by July 2020.

Federal Tax Reform

Based on current regulatory orders received, management anticipates amortization of $249 million of Excess ADIT in 2020 ($68 million of Excess ADIT subject to normalization requirements and $181 million of Excess ADIT that is not subject to normalization requirements). Customer usage or new regulatory orders could result in changes to these estimates. Management anticipates amortizing the following ranges of Excess ADIT that is not subject to normalization requirements over the next five years:

Annual Amortization of Unamortized Balance as of December 31, 2019

Year	Range		
	(in millions)		
2020	$ 165.0	-	$ 196.0
2021	102.0	-	134.0
2022	75.0	-	105.0
2023	67.0	-	98.0
2024	34.0	-	65.0

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 - Acquisitions, Dispositions and Impairments for additional information. Reconstruction activities at Racine are currently 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.

Merchant Portion of Turk Plant

SWEPCo constructed the Turk Plant, a base load 600 MW (650 MW net maximum capacity) pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012 and is included in the Vertically Integrated Utilities segment. SWEPCo owns 73% (440 MWs/477 MWs) of the Turk Plant and operates the facility.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This share of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under cost-based rate recovery in Texas, Louisiana and through SWEPCo's wholesale customers under FERC-based rates. As of December 31, 2019, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission ROE Methodology

In November 2019, the FERC issued Opinion No. 569, which adopted a revised methodology for determining whether an existing base ROE is just and reasonable under Federal Power Act and determined the base ROE for MISO's transmission-owning members should be reduced to 9.88% (10.38% inclusive of RTO incentive adder of 0.5%). The revised ROE methodology relies on two financial models, which include the discounted cash flow model and the capital asset pricing model, to establish a composite zone of reasonableness. In December 2019, AEP filed multiple requests for rehearing and participated in filing comments and requests for rehearing on behalf of transmission owners and industry organizations. Management believes FERC Opinion No. 569 reverses the expectation of a four-model framework proposed by FERC in 2018 and vetted widely in FERC 2019 Notice of Inquiry regarding base ROE policy. Management does not believe this ruling will have a material impact on financial results for its MISO transmission-owning subsidiaries. In the second quarter of 2019, FERC approved settlement agreements establishing base ROEs of 9.85% (10.35% inclusive of RTO incentive adder of 0.5%) and 10% (10.5% inclusive of RTO incentive adder of 0.5%) for AEP's PJM and SPP transmission-owning subsidiaries, respectively. If FERC makes any changes to its ROE and incentive policies, they would be applied to AEP's PJM and SPP transmission owning subsidiaries on a prospective basis, and could affect future net income and cash flows and impact financial condition.

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 6 – 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 stay that expired in February 2020. Settlement negotiations are continuing, and the parties filed a joint proposed case schedule in February 2020. 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 is 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 losses that is reasonably possible of occurring.

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

The American Electric Power System Retirement Plan (the Plan) has received a letter written on behalf of four participants (the Claimants) making a claim for additional plan benefits and purporting to advance such claims on behalf of a class. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The Claimants have asserted claims that (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career; (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act (ADEA); and (c) the company failed to provide required notice regarding the changes to the Plan. AEP has responded to the Claimants providing a reasoned explanation for why each of their claims have been denied, and offering an opportunity to appeal those determinations. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP has a substantial capital investment program and 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 December 31, 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 future investment to meet these existing and proposed requirements ranges from approximately $500 million to $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 December 31, 2019.

Company	Plant Name and Unit	Generating Capacity	Amounts Pending Regulatory Approval
		(in MWs)	(in millions)
APCo (a)	Kanawha River Plant	400	$ 14.1
APCo (b)	Clinch River Plant	705	25.5
APCo (a)	Sporn Plant, Units 1 and 3	300	2.0
APCo (a)	Glen Lyn Plant	335	3.5
SWEPCo (c)	Welsh Plant, Unit 2	528	35.5
Total		2,268	$ 80.6

(a) Remaining amounts pending regulatory approval represent the FERC and the West Virginia jurisdictional share. Management expensed the Virginia jurisdictional share in December 2019. See "Virginia Legislation Affecting Earnings Reviews" section of Note 4 for additional information.

(b) 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.

(c) Remaining amount pending regulatory approval represents the FERC and Louisiana jurisdictional share. The APSC issued an order in December 2019 approving the recovery of the $15 million Arkansas jurisdictional share. See "2019 Arkansas Base Rate Case" section of Note 4 for additional information.

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 Selective Catalytic Reduction 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 Federal EPA is currently reviewing both of these standards. 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.

The Federal EPA finalized non-attainment designations for the 2015 ozone standard in 2018. The Federal EPA 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 were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In August 2019, the court upheld the 2015 primary ozone standard, but remanded the secondary welfare-based standard for further review. The court vacated the Federal EPA's determination that CSAPR fulfilled the states' interstate transport obligations, because the Federal EPA's modeling analysis did not demonstrate that all significant contributions would be eliminated by the attainment deadlines for downwind states. Any further changes will require additional rulemaking. 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.

The Federal EPA initially disapproved portions of the Arkansas regional haze SIP, but has approved a revised SIP and all of SWEPCo's affected units are in compliance with the relevant 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 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. In November 2019, in response to comment, the Federal EPA proposed revisions to the intrastate trading program. Management supports the intrastate trading program 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. Any further changes to the CSAPR rule will require additional rulemaking.

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.

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 of 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 repeal of the CPP and promulgation of a 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 in 2022, and the Federal EPA has up to two years to review and approve a plan or disapprove it 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. AEP 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 2019 were approximately 58 million metric tons, a 65% reduction from AEP's 2000 CO_2 emissions. AEP has made significant progress in reducing CO_2 emissions from its power generation fleet and expects its emissions to continue to decline. AEP's aspirational emissions goal is zero CO_2 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.

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. In November 2019, the Federal EPA proposed revisions to implement the court's decision regarding the timing for closure of unlined surface impoundments along with impoundments not meeting the required distance from an aquifer. The comment period closed in January 2020. In December 2019, the Federal EPA proposed a federal permit program, implementing the Water Infrastructure Improvements for the Nation Act, that would apply in states that do not have an approved CCR program.

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. Additional ARO revisions will occur on a site-by-site basis if groundwater monitoring activities conclude that corrective actions are required to mitigate groundwater impacts, which could include costs to remove ash from some unlined units. In January 2020, a bill was introduced in Virginia to require removal of ash from units at the retired Glen Lyn Station, and provide for recovery of the costs incurred to remove the ash and close those units. If removal of ash is required without providing similar assurances of cost recovery in regulated jurisdictions, it would impose significant additional operating costs on AEP, which could lead to increased financing costs and liquidity needs. Other units in Virginia, Ohio, West Virginia, and Kentucky already have been closed in place in accordance with state law programs. 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. In April 2019, the Fifth Circuit vacated the standards for landfill leachate and legacy wastewater, and remanded them to the Federal EPA for reconsideration. In November 2019, the Federal EPA proposed revisions to the guidelines for existing generation facilities. The comment period ended in January 2020. 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. Various parties challenged the 2015 rule in different U.S. District Courts, which resulted in a patchwork of applicability of the 2015 rule and its predecessor. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers proposed a replacement rule. In September 2019, the Federal EPA repealed the 2015 rule. A final rule was issued in January 2020, which limits that scope of CWA jurisdiction to four categories of waters, and clarifies exclusions for ground water, ephemeral streams, ditches, artificial ponds and waste treatment systems.

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

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

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

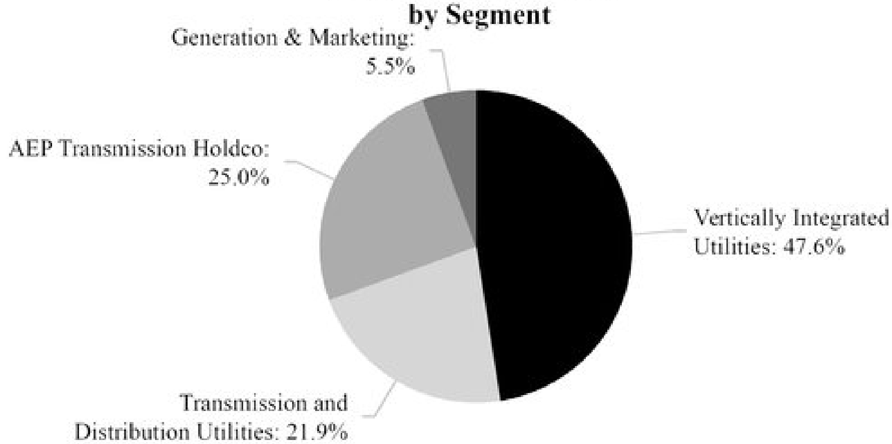
The following discussion of AEP's 2019 results of operations by operating segment includes an analysis of Gross Margin, which is a non-GAAP financial measure. Gross Margin includes Total Revenues less the costs of Fuel and Other Consumables Used for Electric Generation as well as Purchased Electricity for Resale, Generation Deferrals and Amortization of Generation Deferrals as presented in the Registrants' statements of income as applicable. Under the various state utility rate making processes, these expenses are generally reimbursable directly from and billed to customers. As a result, these expenses 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.

A detailed discussion of AEP's 2018 results of operations by operating segment can be found in Management's Discussion and Analysis of Financial Condition and Results of Operation section included in the 2018 Annual Report on Form 10-K filed with the SEC on February 21, 2019.

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

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Vertically Integrated Utilities	$ 982.0	$ 990.5	$ 790.5
Transmission and Distribution Utilities	451.0	527.4	636.4
AEP Transmission Holdco	516.3	369.9	352.1
Generation & Marketing	112.8	135.3	166.0
Corporate and Other	(141.0)	(99.3)	(32.4)
Earnings Attributable to AEP Common Shareholders	$ 1,921.1	$ 1,923.8	$ 1,912.6

2019 Earnings Attributable to AEP Common Shareholders by Segment



Note: 2019 Earnings Attributable to AEP Common Shareholders by Segment excludes Corporate and Other which is not considered a reportable segment.

AEP CONSOLIDATED

2019 Compared to 2018

Earnings Attributable to AEP Common Shareholders decreased $3 million from $1.924 billion in 2018 to $1.921 billion in 2019 primarily due to:

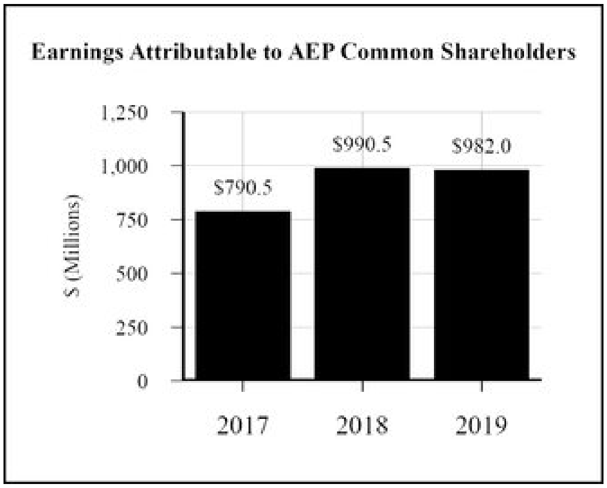
- A decrease in weather-related usage.
- An increase in asset impairments and other related charges.

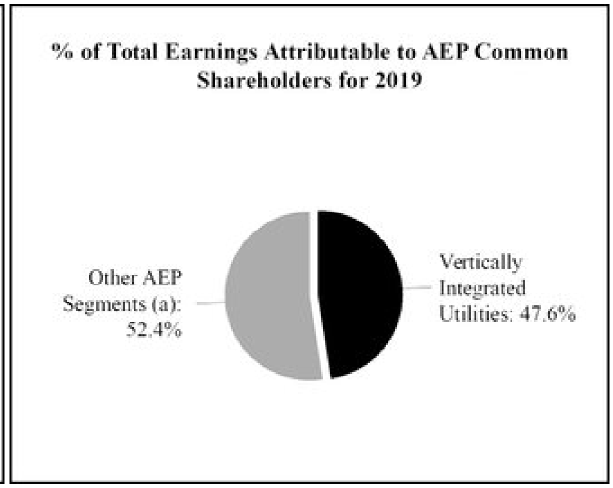
These decreases were partially offset by:

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

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

VERTICALLY INTEGRATED UTILITIES





(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

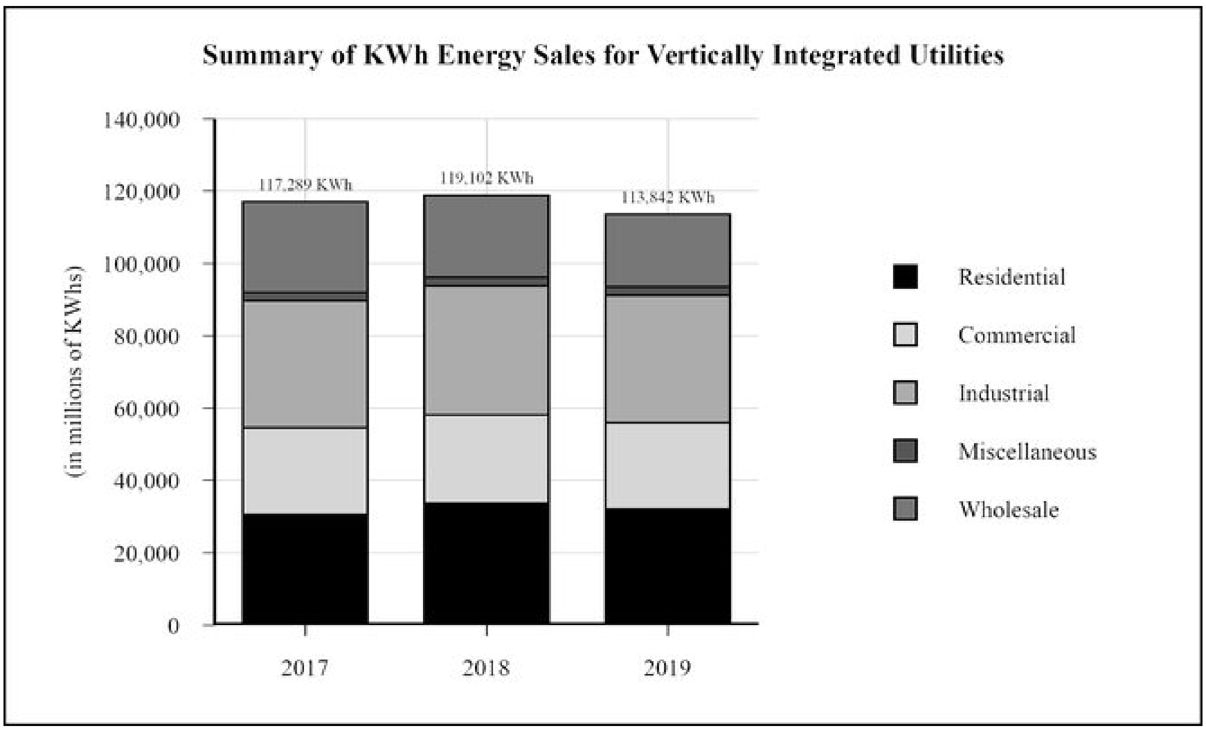
Vertically Integrated Utilities	Years Ended December 31, 2019	2018	2017
		(in millions)	
Revenues	$ 9,367.1	$ 9,645.5	$ 9,192.0
Fuel and Purchased Electricity	3,103.1	3,488.9	3,142.7
Gross Margin	6,264.0	6,156.6	6,049.3
Other Operation and Maintenance	2,934.4	2,959.8	2,760.7
Asset Impairments and Other Related Charges	92.9	3.4	33.6
Depreciation and Amortization	1,447.0	1,316.2	1,142.5
Taxes Other Than Income Taxes	460.9	433.2	413.3
Operating Income	1,328.8	1,444.0	1,699.2
Other Income	6.1	17.0	22.0
Allowance for Equity Funds Used During Construction	50.7	35.4	28.0
Non-Service Cost Components of Net Periodic Benefit Cost	67.6	69.9	23.5
Interest Expense	(568.3)	(567.8)	(540.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	884.9	998.5	1,232.7
Income Tax Expense (Benefit)	(97.7)	5.7	425.6
Equity Earnings (Loss) of Unconsolidated Subsidiary	3.0	2.7	(3.8)
Net Income	985.6	995.5	803.3
Net Income Attributable to Noncontrolling Interests	3.6	5.0	12.8
Earnings Attributable to AEP Common Shareholders	$ 982.0	$ 990.5	$ 790.5

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31,		
	2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	32,359	33,908	30,817
Commercial	23,839	24,452	24,052
Industrial	35,252	35,730	35,043
Miscellaneous	2,302	2,330	2,279
Total Retail (a)	93,752	96,420	92,191
Wholesale (b)	20,090	22,682	25,098
Total KWhs	113,842	119,102	117,289

(a) 2018 and 2017 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.

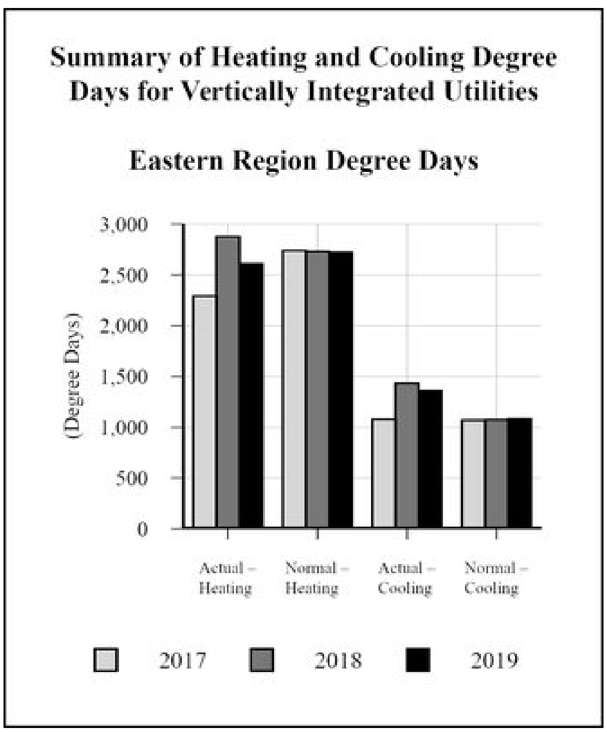


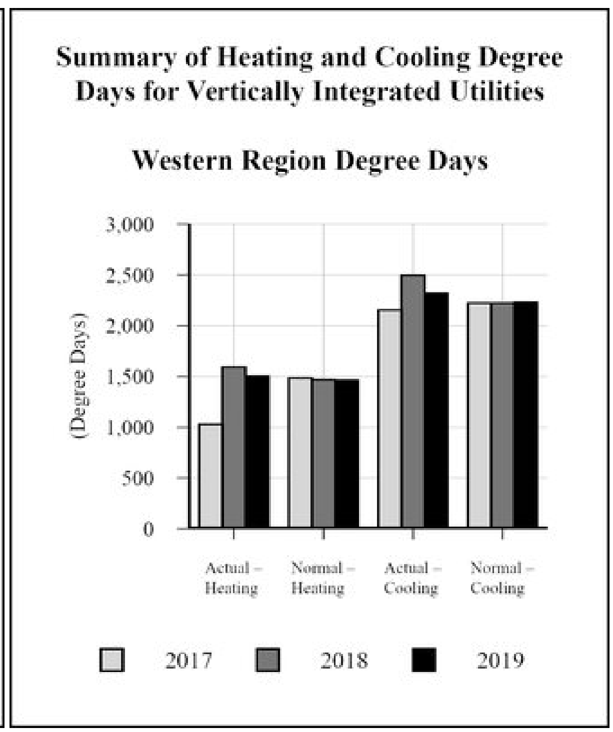
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in degree days)	
Eastern Region			
Actual – Heating (a)	2,617	2,886	2,298
Normal – Heating (b)	2,732	2,738	2,746
Actual – Cooling (c)	1,369	1,443	1,088
Normal – Cooling (b)	1,092	1,083	1,078
Western Region			
Actual – Heating (a)	1,512	1,599	1,040
Normal – Heating (b)	1,473	1,475	1,494
Actual – Cooling (c)	2,328	2,502	2,164
Normal – Cooling (b)	2,240	2,230	2,229

(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.





2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2018	$	990.5
Changes in Gross Margin:		
Retail Margins		134.1
Margins from Off-system Sales		(16.0)
Transmission Revenues		(14.0)
Other Revenues		3.3
Total Change in Gross Margin		107.4
Changes in Expenses and Other:		
Other Operation and Maintenance		25.4
Asset Impairments and Other Related Charges		(89.5)
Depreciation and Amortization		(130.8)
Taxes Other Than Income Taxes		(27.7)
Other Income		(10.9)
Allowance for Equity Funds Used During Construction		15.3
Non-Service Cost Components of Net Periodic Pension Cost		(2.3)
Interest Expense		(0.5)
Total Change in Expenses and Other		(221.0)
Income Tax Expense (Benefit)		103.4
Equity Earnings (Loss) of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interests		1.4
Year Ended December 31, 2019	$	982.0

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 $134 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 offset in Income Tax Expense (Benefit) below.
  - A $30 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.
  - The effect of rate proceedings in AEP's service territories which included:
    - A $112 million increase from rate proceedings at I&M, inclusive of a $24 million decrease due to the impact of Tax Reform. This increase was partially offset in other expense items below.
    - A $46 million increase at PSO due to new base rates implemented in April 2019 and March 2018.
    - A $28 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 $23 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 $21 million increase at APCo and WPCo due to base rate increases in West Virginia implemented in March 2019.
    - A $20 million increase at SWEPCo primarily due to rider and base rate revenue increases in Louisiana and Texas. This increase was offset in other expense items below.
  - 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.

These increases were partially offset by:

- A $120 million decrease due to customer refunds related to Tax Reform primarily at APCo, PSO and SWEPCo. This decrease was partially offset in Income Tax Expense (Benefit) below.
- A $102 million decrease in weather-related usage across all regions primarily in the residential and commercial classes.
- A $61 million decrease in weather-normalized retail margins primarily in the eastern region across all classes.

- **Margins from Off-system Sales** decreased $16 million primarily due to mid-year 2018 changes in the Indiana OSS sharing mechanism at I&M and lower volumes across the system.
- **Transmission Revenues** decreased $14 million primarily due to the following:
  - A $40 million decrease in the annual SPP formula rate true-up at SWEPCo.
  - A $19 million decrease at SWEPCo and PSO primarily due to a decrease in SPP Base Plan Funding Revenues.
  - A $5 million decrease due to a $14 million decrease at I&M, partially offset by a $9 million increase at KPCo and WPCo due to the 2018 PJM Transmission formula rate true-up.

  These decreases were partially offset by:
  - An $18 million increase in the net revenue requirement at APCo.
  - A $16 million increase at APCo due to 2018 PJM provisions for refunds.
  - A $16 million increase due to a provision for refund recorded at SWEPCo and PSO in 2018 related to certain transmission assets that management believes should not have been included in the SPP formula rate.

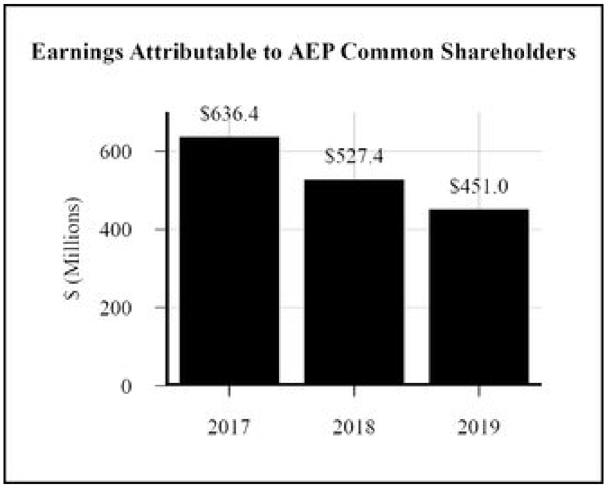
Expenses and Other and Income Tax Expense changed between years as follows:

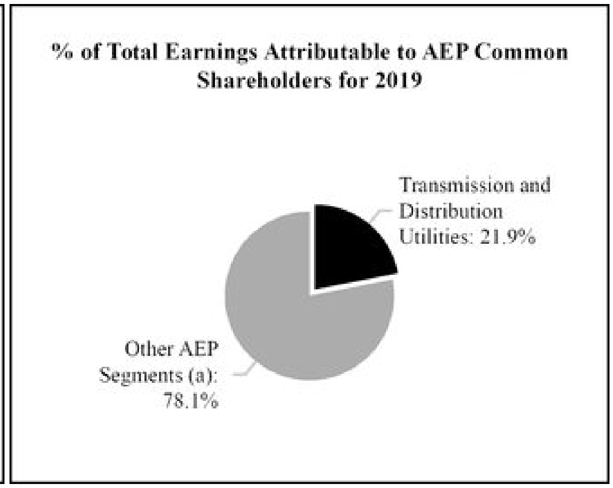
- **Other Operation and Maintenance** expenses decreased $25 million primarily due to the following:
  - A $73 million decrease in planned plant outage and maintenance expenses primarily at I&M, APCo, SWEPCo and KPCo.
  - A $58 million decrease due to SPP transmission services including the annual formula rate true-up.
  - A $40 million decrease due to Wind Catcher Project expenses incurred in 2018 at 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. This decrease is partially offset in Retail Margins above and Income Tax Expense (Benefit) below.
  - A $25 million decrease in recoverable expenses primarily associated with Energy Efficiency/Demand Response and storm-related 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 $10 million decrease in estimated expense for claims related to asbestos exposure.

  These decreases were partially offset by:
  - A $131 million increase due to PJM transmission services including the annual formula rate true-up.
  - A $31 million increase in charitable contributions, primarily to the AEP Foundation.
  - A $25 million increase in employee-related expenses.
  - A $15 million increase at APCo and WPCo 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 due to the modification of the NSR consent decree impacting I&M and AEGCo.
  - A $7 million increase due to North Central Wind Energy Facilities expenses at SWEPCo and PSO.
  - A $4 million increase due to the disallowance of previously recorded capital incentives at SWEPCo as a result of the December 2018 APSC final order.
  - A $4 million increase in accounts receivable factoring expense primarily at I&M and SWEPCo.
- **Asset Impairments and Other Related Charges** increased $90 million primarily due to a pretax expense recorded in 2019 related to previously retired coal-fired assets.
- **Depreciation and Amortization** expenses increased $131 million primarily due to a higher depreciable base and increased depreciation rates approved at APCo, I&M, PSO and SWEPCo.

- **Taxes Other Than Income Taxes** increased $28 million primarily due to the following:
  - A $15 million increase in property taxes driven by an increase in utility plant.
  - A $13 million increase in West Virginia business and occupational taxes at APCo and WPCo.
- **Other Income** decreased $11 million primarily due the following:
  - A $6 million decrease in carrying charges on certain riders at I&M.
  - A $4 million decrease in affiliated interest income at SWEPCo and I&M due to lower Utility Money Pool investment balances.
- **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.
- **Income Tax Expense** decreased $103 million primarily due to additional amortization of Excess ADIT not subject to normalization requirements as a result of finalized rate orders in 2019, a decrease in pretax book income and a decrease in state tax expense. The amortization of Excess ADIT is partially offset in Gross Margin and Other Operation and Maintenance expenses above.

TRANSMISSION AND DISTRIBUTION UTILITIES





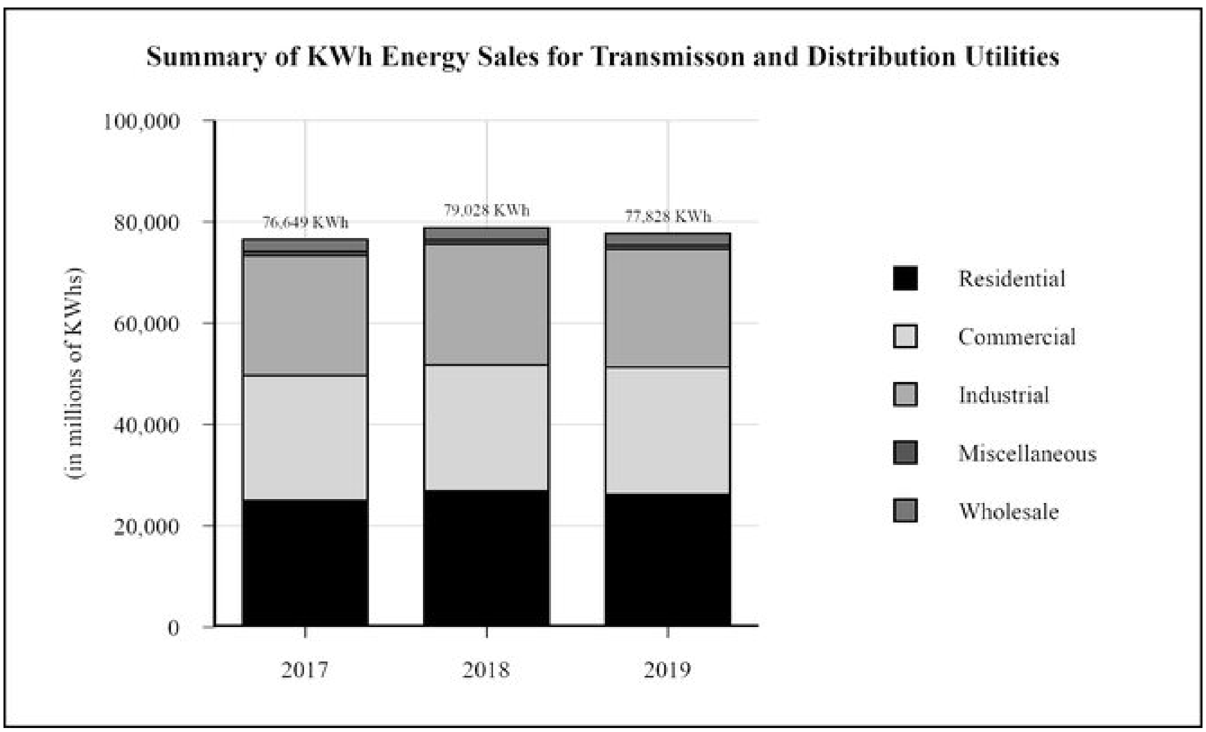
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Transmission and Distribution Utilities	Years Ended December 31, 2019	2018	2017
	(in millions)		
Revenues	$ 4,482.5	$ 4,653.1	$ 4,419.3
Purchased Electricity	794.3	858.3	835.3
Amortization of Generation Deferrals	65.3	223.9	229.2
Gross Margin	3,622.9	3,570.9	3,354.8
Other Operation and Maintenance	1,628.1	1,541.7	1,199.3
Asset Impairments and Other Related Charges	32.5	—	—
Depreciation and Amortization	789.5	734.1	667.5
Taxes Other Than Income Taxes	575.0	545.3	513.7
Operating Income	597.8	749.8	974.3
Interest and Investment Income	6.6	4.2	7.7
Carrying Costs Income	1.0	1.7	3.6
Allowance for Equity Funds Used During Construction	33.4	29.9	13.2
Non-Service Cost Components of Net Periodic Benefit Cost	30.3	32.3	8.9
Interest Expense	(243.3)	(248.1)	(244.1)
Income Before Income Tax Expense (Benefit)	425.8	569.8	763.6
Income Tax Expense (Benefit)	(25.2)	42.4	127.2
Net Income	451.0	527.4	636.4
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 451.0	$ 527.4	$ 636.4

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31,		
	2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	26,407	27,042	25,108
Commercial	25,018	24,877	24,724
Industrial	23,289	23,908	23,673
Miscellaneous	779	760	757
Total Retail (a)(b)	75,493	76,587	74,262
Wholesale (c)	2,335	2,441	2,387
Total KWhs	77,828	79,028	76,649

(a) 2018 and 2017 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 into PJM.

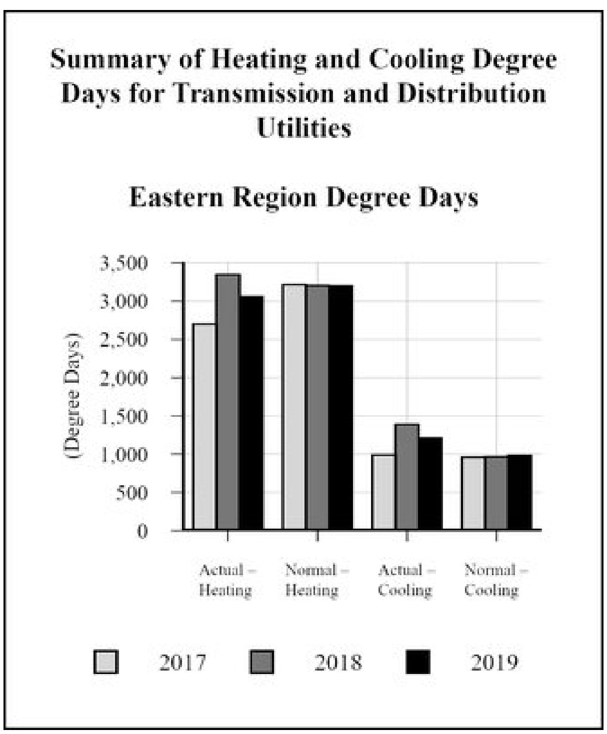


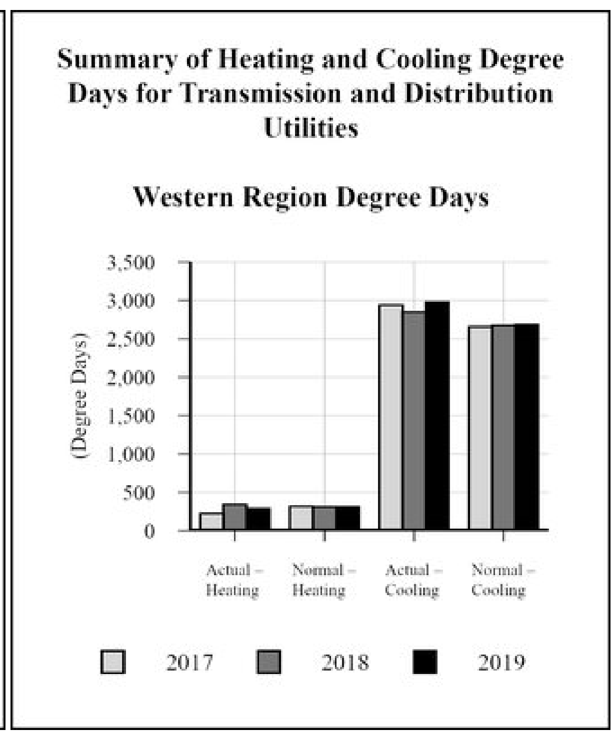
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two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

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

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in degree days)	
Eastern Region			
Actual – Heating (a)	3,071	3,357	2,709
Normal – Heating (b)	3,208	3,215	3,225
Actual – Cooling (c)	1,224	1,402	1,002
Normal – Cooling (b)	992	980	974
Western Region			
Actual – Heating (a)	301	354	239
Normal – Heating (b)	322	325	330
Actual – Cooling (d)	2,989	2,861	2,950
Normal – Cooling (b)	2,699	2,688	2,669

(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.





2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2018	$ 527.4
Changes in Gross Margin:	
Retail Margins	(65.2)
Margins from Off-system Sales	11.8
Transmission Revenues	85.6
Other Revenues	19.8
Total Change in Gross Margin	52.0
Changes in Expenses and Other:	
Other Operation and Maintenance	(86.4)
Asset Impairments and Other Related Charges	(32.5)
Depreciation and Amortization	(55.4)
Taxes Other Than Income Taxes	(29.7)
Interest and Investment Income	2.4
Carrying Costs Income	(0.7)
Allowance for Equity Funds Used During Construction	3.5
Non-Service Cost Component of Net Periodic Benefit Cost	(2.0)
Interest Expense	4.8
Total Change in Expenses and Other	(196.0)
Income Tax Expense (Benefit)	67.6
Year Ended December 31, 2019	$ 451.0

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

- **Retail Margins** decreased $65 million primarily due to the following:
  - A $103 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 $30 million decrease due to a provision for refund in the 2019 Texas Base Rate Case.
  - A $25 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 $22 million decrease in revenues associated with a vegetation management rider in Ohio. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $21 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 $21 million net decrease in margin in Ohio for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $10 million decrease in weather-normalized margins primarily in the residential and commercial classes.

  These decreases were partially offset by:
  - A $58 million increase due to a reversal of a regulatory provision in Ohio.
  - A $41 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.
  - 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 $30 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.
- An $11 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 $12 million primarily due to the following:
  - A $42 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 $31 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 $86 million primarily due to recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $20 million primarily due to the following:
  - An $11 million increase primarily due to securitization revenue. This increase was offset below in Depreciation and Amortization expenses and in Interest Expense.
  - A $7 million increase primarily due to distribution connection fees and pole attachment revenues in Ohio.

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

- **Other Operation and Maintenance** expenses increased $86 million primarily due to the following:
  - A $68 million increase in PJM expenses primarily related to the annual formula rate true-up.
  - 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 $49 million increase in affiliated PPA expenses in Texas. This increase was offset in Margins from Off-system Sales above.
  - A $12 million increase due to a charitable contribution to the AEP Foundation.

  These increases were partially offset by:
  - A $117 million decrease in transmission expenses that were fully recovered in rate riders/trackers in Gross Margin above.
- **Asset Impairments and Other Related Charges** increased $33 million due to regulatory disallowances in the 2019 Texas Base Rate Case.
- **Depreciation and Amortization** expenses increased $55 million primarily due to the following:
  - A $68 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $17 million increase in securitization amortizations in Texas. This increase was offset in Other Revenues above and in Interest Expense below.
  - An $11 million increase due to lower deferred equity amortizations associated with the Deferred Asset Phase-In-Recovery Rider in Ohio which ended in the second quarter of 2019.
  - A $6 million increase in depreciation expense related to the Oklaunion Power Station.

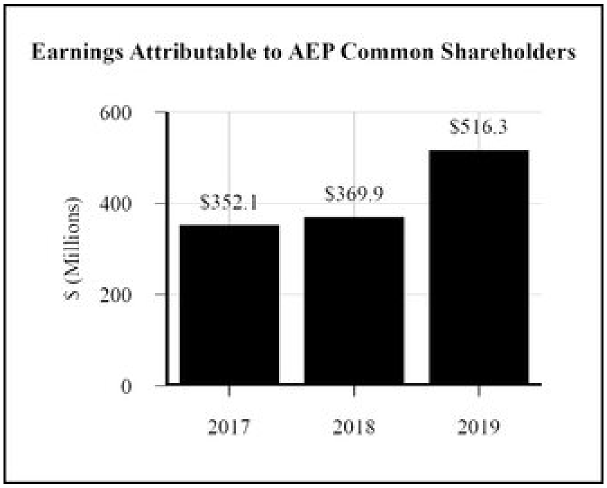
  These increases were partially offset by:
  - A $26 million decrease in Ohio recoverable DIR depreciation expense. This decrease was partially offset in Retail Margins above.
  - A $23 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider in Ohio which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $30 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 $4 million primarily due to the following:
  - An $8 million increase in Ohio primarily due to adjustments that resulted from 2019 FERC audit findings.

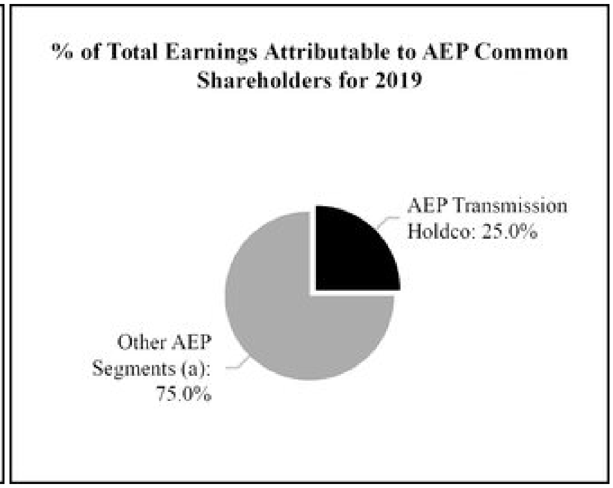
  This increase was partially offset by:
  - A $5 million decrease in the Equity component as a result of higher short-term debt balances, partially offset by increased transmission projects.

- **Interest Expense** decreased $5 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 $11 million decrease in expense related to Securitization assets. This decrease was offset in Other Revenues and Depreciation and Amortization expenses above.

  These decreases were partially offset by:
  - A $22 million increase due to higher long-term debt balances.
  - A $2 million increase due to higher short-term debt balances.
- **Income Tax Expense (Benefit)** decreased $68 million primarily due to an increase in 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 and a decrease in pretax book income. This decrease was partially offset above in Retail Margins and Other Operation and Maintenance expenses.

AEP TRANSMISSION HOLDCO



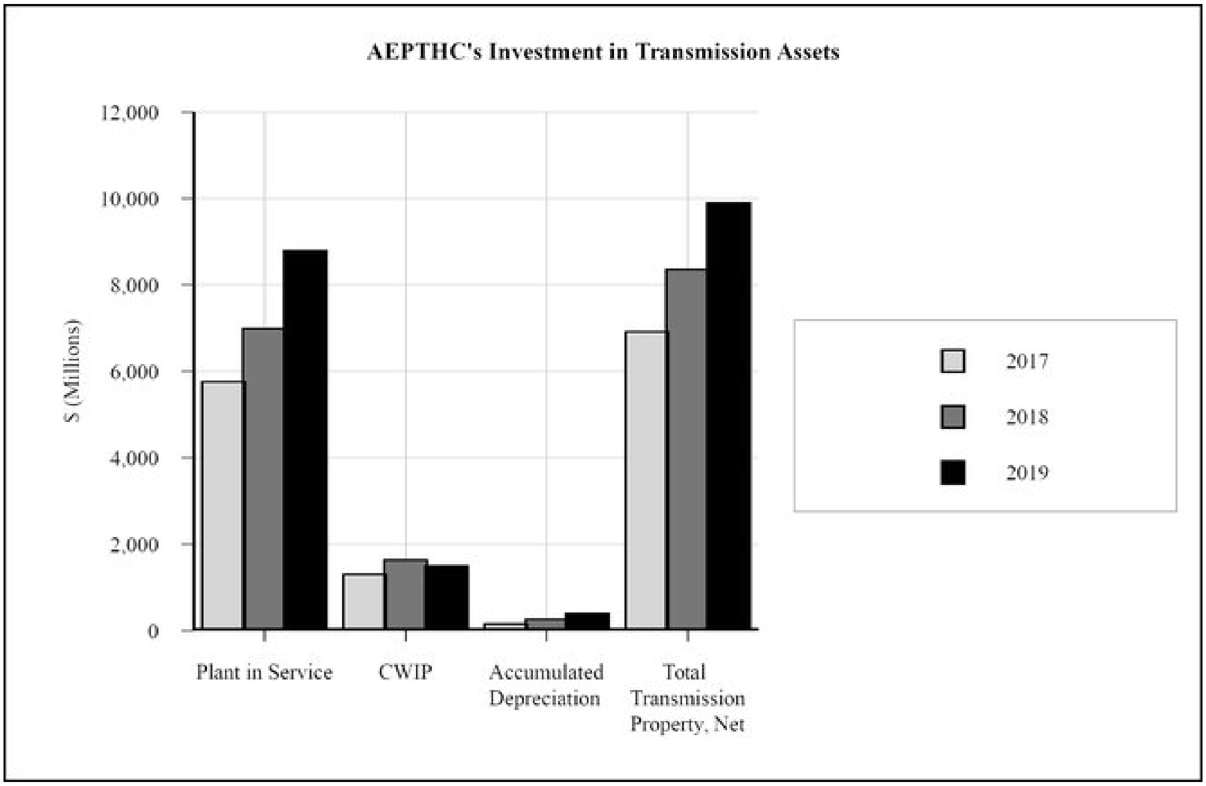


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

AEP Transmission Holdco	Years Ended December 31, 2019	2018	2017
		(in millions)	
Transmission Revenues	$ 1,073.2	$ 804.1	$ 766.7
Other Operation and Maintenance	119.0	105.6	74.7
Depreciation and Amortization	183.4	137.8	102.2
Taxes Other Than Income Taxes	174.4	142.3	114.0
Operating Income	596.4	418.4	475.8
Other Income	3.4	2.1	1.0
Allowance for Equity Funds Used During Construction	84.3	67.2	52.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.7	2.6	0.3
Interest Expense	(103.3)	(90.7)	(72.8)
Income Before Income Tax Expense and Equity Earnings	583.5	399.6	456.8
Income Tax Expense	136.2	95.3	189.8
Equity Earnings of Unconsolidated Subsidiary	72.8	68.7	88.6
Net Income	520.1	373.0	355.6
Net Income Attributable to Noncontrolling Interests	3.8	3.1	3.5
Earnings Attributable to AEP Common Shareholders	$ 516.3	$ 369.9	$ 352.1

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	December 31, 2019	December 31, 2018	December 31, 2017
	(in millions)		
Plant in Service	$ 8,812.2	$ 7,008.4	$ 5,784.6
Construction Work in Progress	1,521.8	1,651.1	1,325.6
Accumulated Depreciation and Amortization	418.9	282.8	176.6
Total Transmission Property, Net	$ 9,915.1	$ 8,376.7	$ 6,933.6



2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2018	$	369.9
Changes in Transmission Revenues:		
Transmission Revenues		269.1
Total Change in Transmission Revenues		269.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(13.4)
Depreciation and Amortization		(45.6)
Taxes Other Than Income Taxes		(32.1)
Other Income		1.3
Allowance for Equity Funds Used During Construction		17.1
Non-Service Cost Components of Net Periodic Pension Cost		0.1
Interest Expense		(12.6)
Total Change in Expenses and Other		(85.2)
Income Tax Expense		(40.9)
Equity Earnings of Unconsolidated Subsidiary		4.1
Net Income Attributable to Noncontrolling Interests		(0.7)
Year Ended December 31, 2019	$	516.3

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

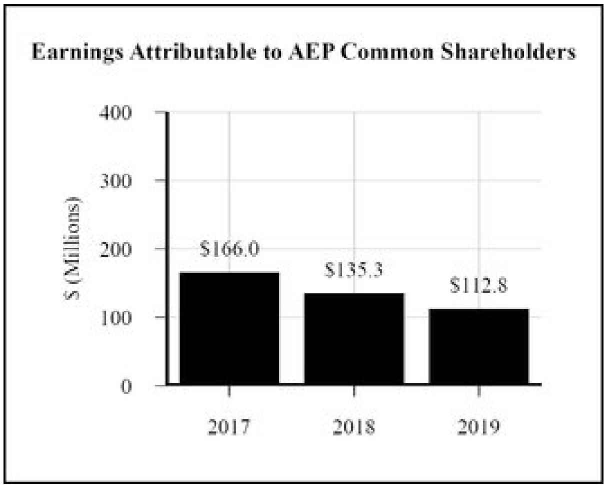
- **Transmission Revenues** increased $269 million primarily due to continued investment in transmission assets.

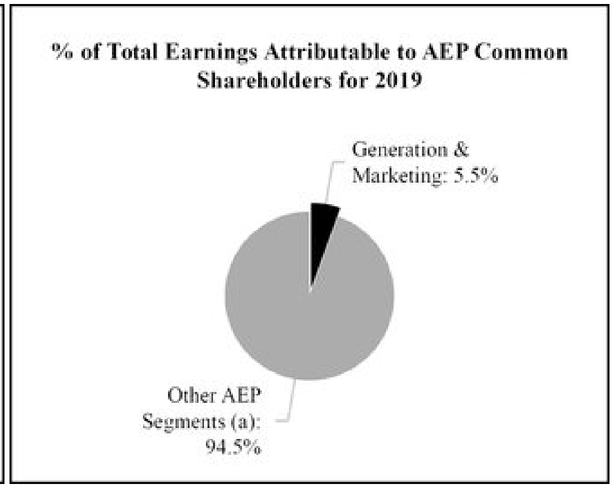
Expenses and Other, Income Tax Expense and Equity Earnings of Unconsolidated Subsidiaries changed between years as follows:

- **Other Operation and Maintenance** expenses increased $13 million primarily due to the following:
  - A $7 million increase due to a charitable contribution to the AEP Foundation.
  - A $6 million increase due to continued investment in transmission assets.
- **Depreciation and Amortization** expenses increased $46 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $32 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $17 million primarily due to the following:
  - An $18 million increase due to higher monthly 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 $13 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $41 million primarily due to higher pretax book income.
- **Equity Earnings of Unconsolidated Subsidiaries** increased $4 million primarily due to higher pretax equity earnings at ETT.

GENERATION & MARKETING



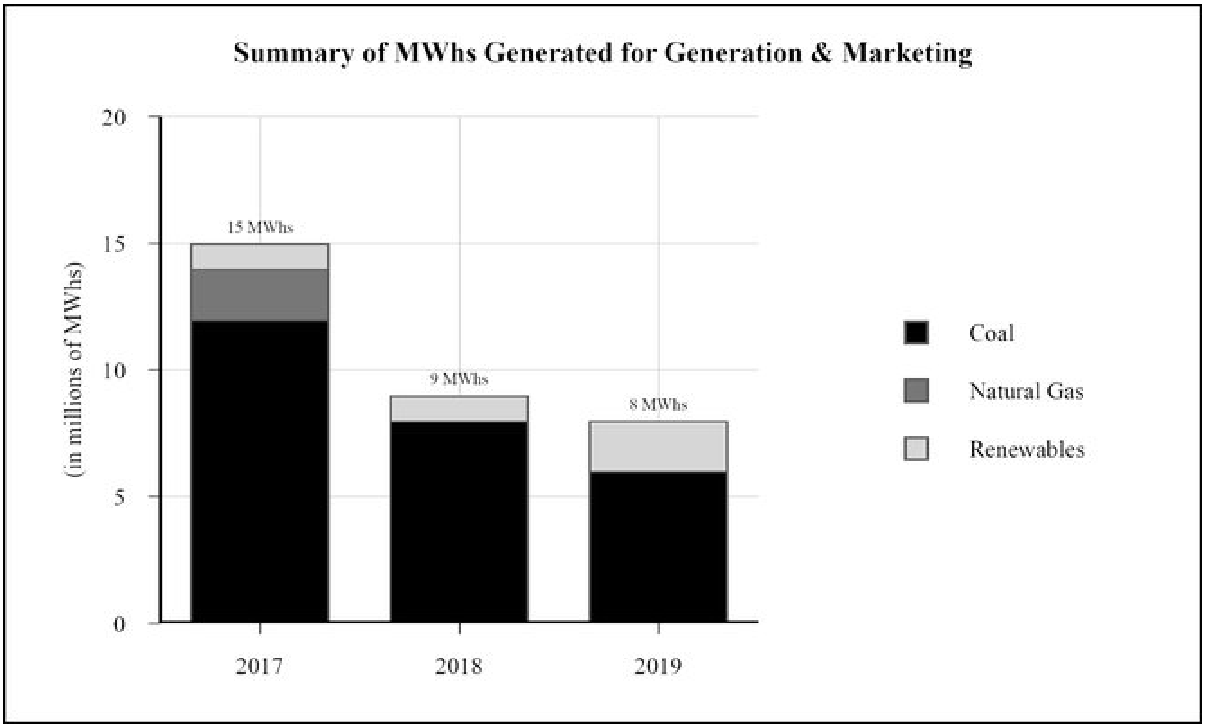


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Generation & Marketing	Years Ended December 31, 2019	2018	2017
		(in millions)	
Revenues	$ 1,857.6	$ 1,940.3	$ 1,875.1
Fuel, Purchased Electricity and Other	1,456.2	1,537.3	1,377.2
Gross Margin	401.4	403.0	497.9
Other Operation and Maintenance	223.8	229.3	279.5
Asset Impairments and Other Related Charges	31.0	47.7	53.5
Gain on Sale of Merchant Generation Assets	—	—	(226.4)
Depreciation and Amortization	69.5	41.0	24.2
Taxes Other Than Income Taxes	15.6	13.4	12.1
Operating Income	61.5	71.6	355.0
Interest and Investment Income	7.7	13.1	10.3
Non-Service Cost Components of Net Periodic Benefit Cost	14.9	15.2	8.9
Interest Expense	(30.0)	(14.9)	(18.5)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	54.1	85.0	355.7
Income Tax Expense (Benefit)	(53.8)	(49.2)	189.7
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(3.8)	0.5	—
Net Income	104.1	134.7	166.0
Net Loss Attributable to Noncontrolling Interests	(8.7)	(0.6)	—
Earnings Attributable to AEP Common Shareholders	$ 112.8	$ 135.3	$ 166.0

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31,		
	2019	2018	2017
	(in millions of MWhs)		
Fuel Type:			
Coal	6	8	12
Natural Gas	—	—	2
Renewables	2	1	1
Total MWhs	8	9	15



2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2018	$	135.3
Changes in Gross Margin:		
Merchant Generation		(73.3)
Renewable Generation		31.9
Retail, Trading and Marketing		39.8
Total Change in Gross Margin		(1.6)
Changes in Expenses and Other:		
Other Operation and Maintenance		5.5
Asset Impairments and Other Related Charges		16.7
Depreciation and Amortization		(28.5)
Taxes Other Than Income Taxes		(2.2)
Interest and Investment Income		(5.4)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(15.1)
Total Change in Expenses and Other		(29.3)
Income Tax Expense (Benefit)		4.6
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(4.3)
Net Loss Attributable to Noncontrolling Interests		8.1
Year Ended December 31, 2019	$	112.8

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:

- **Merchant Generation** decreased $73 million primarily due to the following:
  - A $42 million decrease due to reduced capacity and energy margins.
  - A $17 million decrease due to the retirement of the Stuart Plant in 2018.
  - A $14 million decrease due to the retirement of Conesville Units 5 and 6 in 2019.
- **Renewable Generation** increased $32 million primarily due to the Sempra Renewables LLC acquisition and other renewable projects placed in-service.
- **Retail, Trading and Marketing** increased $40 million due to higher retail margins due to lower market costs and higher delivered volumes and higher marketing activity in 2019.

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

- **Other Operation and Maintenance** expenses decreased $6 million primarily due to the retirement of the Stuart Plant and Conesville Units 5 and 6 partially offset by expenses related to the Sempra Renewables LLC acquisition and increased investments in wind farms and renewable energy sources.
- **Asset Impairments and Other Related Charges** decreased $17 million primarily due to a $35 million decrease in impairment charges related to Racine partially offset by a $19 million increase in impairment charges related to the Conesville plant in 2019.
- **Depreciation and Amortization** expenses increased $29 million primarily due to a higher depreciable base from increased investments in renewable energy sources.

- **Interest Expense** increased $15 million primarily due to increased borrowing costs related to the Sempra Renewables LLC acquisition.
- **Income Tax Expense (Benefit)** increased $5 million primarily due to an increase in income and production tax credits related to the Sempra Renewables LLC and Santa Rita East acquisitions. This increase was partially offset by a decrease in parent savings in 2019.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $4 million primarily due to the Sempra Renewables LLC acquisition.
- **Net Loss Attributed to Noncontrolling Interests** increased $8 million primarily due to the Sempra Renewables LLC acquisition.

CORPORATE AND OTHER

2019 Compared to 2018

Earnings attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $99 million in 2018 to a loss of $141 million in 2019 primarily due to:

- A $71 million increase in interest expense as a result of increased debt outstanding.
- A $12 million increase in general corporate expenses.
- A $6 million increase in tax expense primarily due to the following:
  - A $23 million increase in state income tax expense related to unitary state filing requirements.
  - An $18 million increase related to the enactment of the Kentucky state tax legislation in the second quarter of 2018.
  - 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.

  These increases were partially offset by:
  - A $43 million decrease due to a decrease in the allocation of the parent company loss benefit due to the tax sharing agreement.
- A $5 million write-off 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 $18 million increase in interest income from affiliates.
- A $16 million increase in interest income due to a higher return on investments held by EIS.

AEP SYSTEM INCOME TAXES

2019 Compared to 2018

Income Tax Expense decreased $128 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements as a result of finalized rate orders in 2019, an increase in income and production tax credits driven by the Sempra Renewables LLC and Santa Rita East acquisitions and a decrease in pretax book income.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2019		2018	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 26,725.5	54.1%	$ 23,346.7	52.7%
Short-term Debt	2,838.3	5.7	1,910.0	4.3
Total Debt	29,563.8	59.8	25,256.7	57.0
AEP Common Equity	19,632.2	39.6	19,028.4	42.9
Noncontrolling Interests	281.0	0.6	31.0	0.1
Total Debt and Equity Capitalization	$ 49,477.0	100.0%	$ 44,316.1	100.0%

AEP's ratio of debt-to-total capital increased from 57.0% to 59.8% as of December 31, 2018 and 2019, respectively, 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 December 31, 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 December 31, 2019, available liquidity was $2.1 billion as illustrated in the table below:

	Amount	Maturity
	(in millions)	
Commercial Paper Backup:		
Revolving Credit Facility	$ 4,000.0	June 2022
Cash and Cash Equivalents	246.8	
Total Liquidity Sources	4,246.8	
Less: AEP Commercial Paper Outstanding	2,110.0	
Net Available Liquidity	$ 2,136.8	

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 2019 was $2.2 billion. The weighted-average interest rate for AEP's commercial paper during 2019 was 2.51%.

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 December 31, 2019, was $207 million with maturities ranging from January 2020 to December 2020.

Financing Plan

As of December 31, 2019, AEP had $1.6 billion of long-term debt due within one year. This included $431 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current and $392 million of securitization bonds and DCC Fuel notes. Management plans to refinance the majority of the maturities due within one year on a long-term basis.

Securitized Accounts Receivables

AEP 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 December 31, 2019, this contractually-defined percentage was 57.4%. 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 14 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.70 per share in January 2020. 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 14 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.

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 444.1	$ 412.6	$ 403.5
Net Cash Flows from Operating Activities	4,270.1	5,223.2	4,270.4
Net Cash Flows Used for Investing Activities	(7,144.5)	(6,353.6)	(3,656.4)
Net Cash Flows from (Used for) Financing Activities	2,862.9	1,161.9	(604.9)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(11.5)	31.5	9.1
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 432.6	$ 444.1	$ 412.6

Operating Activities

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Net Income	$ 1,919.8	$ 1,931.3	$ 1,928.9
Non-Cash Adjustments to Net Income (a)	2,685.7	2,400.0	2,822.6
Mark-to-Market of Risk Management Contracts	(29.2)	(66.4)	(23.3)
Pension Contributions to Qualified Plan Trust	—	—	(93.3)
Property Taxes	(73.8)	(59.1)	(29.5)
Deferred Fuel Over/Under Recovery, Net	85.2	189.7	84.4
Recovery of Ohio Capacity Costs, Net	34.1	67.7	83.2
Refund of Global Settlement	(16.5)	(5.5)	(98.2)
Change in Other Noncurrent Assets	(97.4)	119.8	(423.9)
Change in Other Noncurrent Liabilities	(116.1)	129.0	181.7
Change in Certain Components of Working Capital	(121.7)	516.7	(162.2)
Net Cash Flows from Operating Activities	$ 4,270.1	$ 5,223.2	$ 4,270.4

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Rockport Plant Unit 2 Operating Lease Amortization, Deferred Income Taxes, Asset Impairments and Other Related Charges, Allowance for Equity Funds Used During Construction, Amortization of Nuclear Fuel, Pension and Postemployment Benefit Reserves and Gain on Sale of Merchant Generation Assets.

2019 Compared to 2018

Net Cash Flows from Operating Activities decreased by $953 million primarily due to the following:

- A $638 million decrease in cash from Changes in Certain Components of Working Capital. This decrease was primarily due to an increase in fuel, material and supplies balances as a result of mild winter weather, the addition of operating lease payments due to the adoption of ASU 2016-02, higher employee-related benefits and revenue refunds related to Tax Reform. These decreases were partially offset by timing of accounts receivables.
- A $245 million decrease in cash from Change in Other Noncurrent Liabilities primarily due to increases in revenue refunds related to Tax Reform and Ohio regulatory liabilities.
- A $217 million decrease in cash from Changes 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 $105 million decrease in cash from Deferred Fuel Over/Under Recovery, Net primarily due to the full recovery of the Ohio Phase-in-Recovery Rider and prior year reduction of ENEC balances at APCo and WPCo as a result of the 2018 West Virginia Tax Reform Order, partially offset by net rate and weather fluctuations across jurisdictions. See Note 4 - Rate Matters for additional information.

These decreases in cash were partially offset by:

- A $274 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.

Investing Activities

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Construction Expenditures	$ (6,051.4)	$ (6,310.9)	$ (5,691.3)
Acquisitions of Nuclear Fuel	(92.3)	(46.1)	(108.0)
Acquisition of Sempra Renewables LLC and Santa Rita East, net of cash and restricted cash acquired	(918.4)	—	—
Proceeds from Sale of Merchant Generation Assets	—	—	2,159.6
Other	(82.4)	3.4	(16.7)
Net Cash Flows Used for Investing Activities	$ (7,144.5)	$ (6,353.6)	$ (3,656.4)

2019 Compared to 2018

Net Cash Flows Used for Investing Activities increased by $791 million primarily due to the following:

- A $918 million increase due to the acquisition of Sempra Renewables LLC and Santa Rita East. The $918 million represents a cash payment of $936 million, net of cash and restricted cash acquired of $18 million. See Note 7 - Acquisitions, Dispositions and Impairments for additional information.

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

- A $260 million decrease in construction expenditures primarily due to decreases in Generation & Marketing.

Financing Activities

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Issuance of Common Stock	$ 65.3	$ 73.6	$ 12.2
Issuance/Retirement of Debt, Net	4,244.1	2,435.1	691.8
Dividends Paid on Common Stock	(1,350.0)	(1,255.5)	(1,191.9)
Other	(96.5)	(91.3)	(117.0)
Net Cash Flows from (Used for) Financing Activities	$ 2,862.9	$ 1,161.9	$ (604.9)

2019 Compared to 2018

Net Cash Flows from Financing Activities increased by $1.7 billion primarily due to the following:

- A $1.6 billion increase in cash due to decreased retirements of long-term debt. See Note 14 - Financing Activities for additional information.
- A $657 million increase in cash from short-term debt primarily due to increased borrowings of commercial paper. See Note 14 - Financing Activities for additional information.

These increases in cash were partially offset by:

- A $409 million decrease in issuance of long-term debt. See Note 14 - Financing Activities for additional information.

The following financing activities occurred during 2019:

AEP Common Stock:

- During 2019, AEP issued 924 thousand shares of common stock under the incentive compensation, employee saving and dividend reinvestment plans and received net proceeds of $65 million.

Debt:

- During 2019, AEP issued approximately $4.6 billion of long-term debt, including $2.7 billion of senior unsecured notes at interest rates ranging from 3.15% to 4.5%, $805 million of junior subordinated debenture note at interest rate of 3.4%, $771 million of pollution control bonds at interest rates ranging from 1.35% to 2.60%, and $375 million of other debt at various interest rates. The proceeds from these issuances were used to fund long-term debt maturities and construction programs.
- During 2019, AEP entered into interest rate derivatives with notional amounts totaling $125 million that were designated as cash flow hedges. As of December 31, 2019, AEP had a total notional amount of $125 million of interest rate derivatives designated as cash flow hedges. During 2019, settlements of AEP's interest rate derivatives designated as fair value hedges resulted in net cash paid of $1.5 million. As of December 31, 2019, AEP had a total notional amount of $500 million of outstanding interest rate derivatives designated as fair value hedges.

In 2020:

In January and February 2020, AEP Texas retired $111 million and $3 million, respectively, of Securitization Bonds.

In January and February 2020, I&M retired $8 million and $5 million, respectively, of Notes Payable related to DCC Fuel.

In January 2020, Transource Energy issued $4 million of variable rate Other Long-term Debt due in 2023.

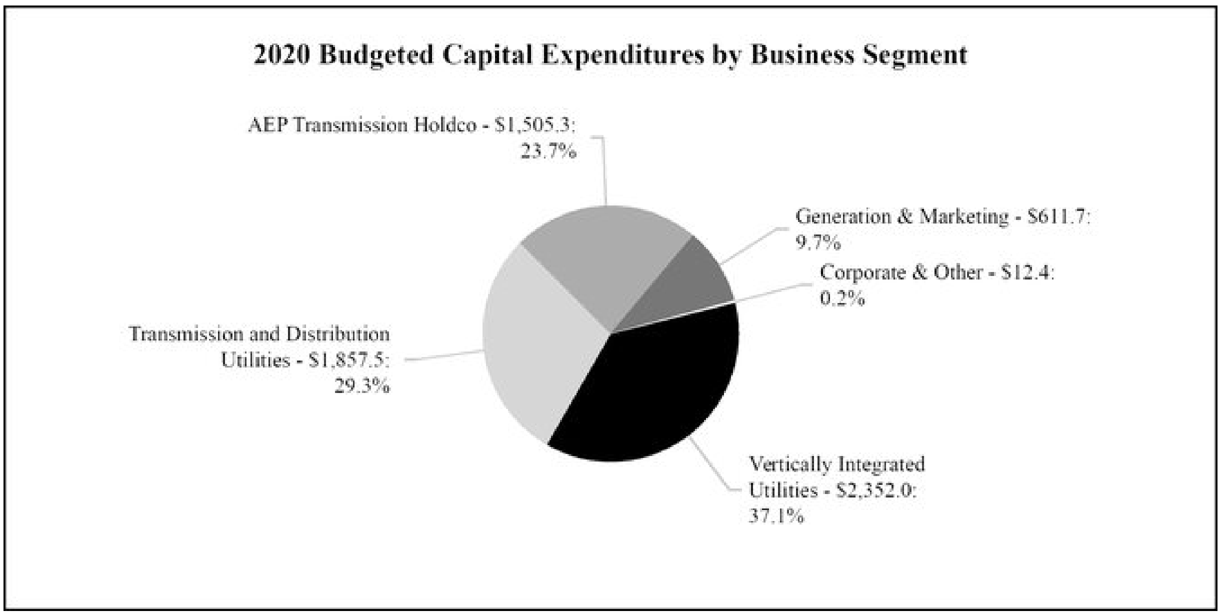
In February 2020, APCo retired $12 million of Securitization Bonds.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $6.3 billion of capital expenditures in 2020. For the four year period, 2021 through 2024, management forecasts capital expenditures of $26.6 billion. 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. The 2020 estimated capital expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2020 Budgeted Capital Expenditures					
Segment	**Environmental**	**Generation**	**Transmission**	**Distribution**	**Other (a)**	**Total**
			(in millions)			
Vertically Integrated Utilities	$ 165.1	$ 277.2	$ 701.0	$ 899.6	$ 309.1	$ 2,352.0
Transmission and Distribution Utilities	—	1.8	765.3	870.9	219.5	1,857.5
AEP Transmission Holdco	—	—	1,452.0	—	53.3	1,505.3
Generation & Marketing	11.0	571.8	—	—	28.9	611.7
Corporate and Other	—	—	—	—	12.4	12.4
Total	$ 176.1	$ 850.8	$ 2,918.3	$ 1,770.5	$ 623.2	$ 6,338.9

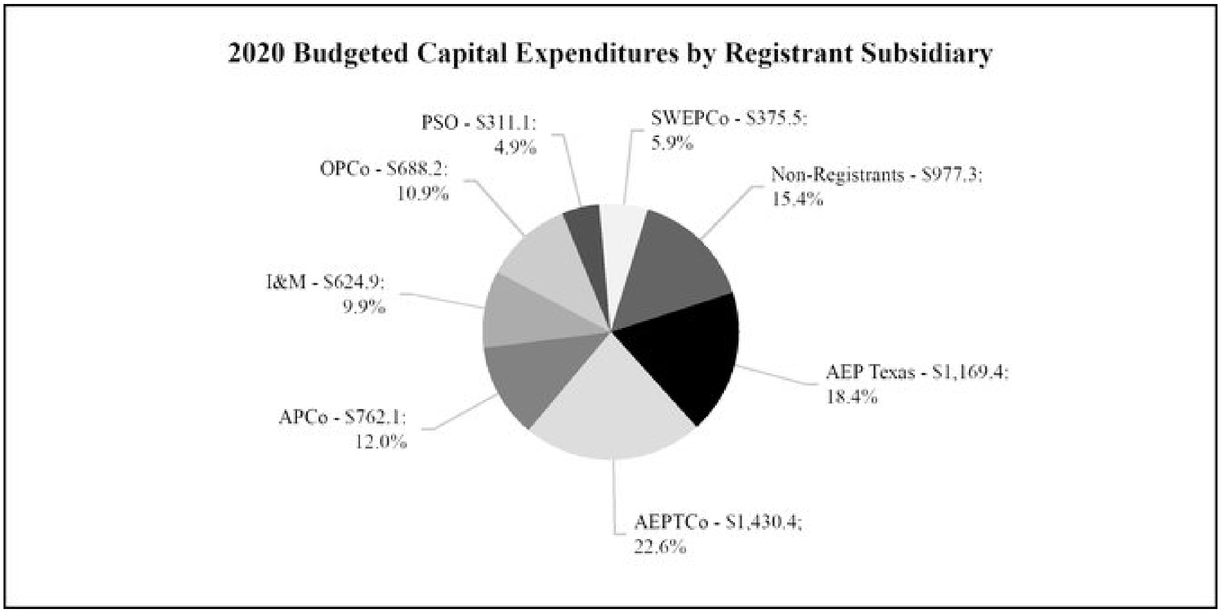
(a) Amount primarily consists of facilities, software and telecommunications.



The 2020 estimated capital expenditures by Registrant Subsidiary include distribution, transmission and generation related investments, as well as expenditures for compliance with environmental regulations as follows:

	2020 Budgeted Capital Expenditures					
Company	Environmental	Generation	Transmission	Distribution	Other (a)	Total
			(in millions)			
AEP Texas	$ —	$ 1.8	$ 629.4	$ 443.5	$ 94.7	$ 1,169.4
AEPTCo	—	—	1,374.1	—	56.3	1,430.4
APCo	37.3	43.4	339.7	267.7	74.0	762.1
I&M	33.4	153.8	83.6	248.7	105.4	624.9
OPCo	—	—	135.9	427.4	124.9	688.2
PSO	6.0	21.2	49.7	183.8	50.4	311.1
SWEPCo	40.1	39.5	126.5	122.6	46.8	375.5

(a) Amount primarily consists of facilities, software and telecommunications.



CONTRACTUAL OBLIGATION INFORMATION

AEP's contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in the footnotes. The following table summarizes AEP's contractual cash obligations as of December 31, 2019:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 2,838.3	$ —	$ —	$ —	$ 2,838.3
Interest on Fixed Rate Portion of Long-term Debt (b)	28.8	45.2	31.7	29.3	135.0
Fixed Rate Portion of Long-term Debt (c)	1,070.4	4,238.3	1,271.3	18,863.1	25,443.1
Variable Rate Portion of Long-term Debt (d)	528.3	799.0	175.1	—	1,502.4
Finance Lease Obligations (e)	72.7	121.3	107.0	64.4	365.4
Operating Lease Obligations (e)	269.9	499.2	136.8	169.7	1,075.6
Fuel Purchase Contracts (f)	1,047.0	1,105.0	234.4	111.4	2,497.8
Energy and Capacity Purchase Contracts	227.8	353.2	273.5	1,080.0	1,934.5
Construction Contracts for Capital Assets (g)	2,121.2	3,752.4	2,992.8	3,382.7	12,249.1
Total	$ 8,204.4	$ 10,913.6	$ 5,222.6	$ 23,700.6	$ 48,041.2

(a) Represents principal only, excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2019 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14 for additional information. Represents principal only, excluding interest.
(d) See "Long-term Debt" section of Note 14 for additional information. Represents principal only, excluding interest. Variable rate debt had interest rates that ranged between 1.67% and 3.20% as of December 31, 2019.
(e) See Note 13 - Leases for additional information.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

AEP's pension funding requirements are not included in the above table. As of December 31, 2019, AEP expects to make contributions to the pension plans totaling $6 million in 2020. Estimated contributions of $119 million in 2021 and $123 million in 2022 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, the pension plans were 95.8% funded as of December 31, 2019. See "Estimated Future Benefit Payments and Contributions" section of Note 8 for additional information.

In addition to the amounts disclosed in the contractual cash obligations table above, 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. There is no collateral held in relation to any guarantees in excess of the ownership percentages. In the event any letters of credit are drawn, there is no recourse to third-parties. See "Letters of Credit" section of Note 6 for additional information.

SIGNIFICANT TAX LEGISLATION

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, the Registrants' deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In December 2019, a tax extenders bill was signed into law to extend wind PTCs an additional year. Wind projects that begin construction in 2020 are now eligible for a 60% PTC or alternatively an 18% ITC in lieu of a PTC. See "Federal Tax Reform and Legislation" and "State Tax Legislation" sections of Note 12 for additional information.

CYBER SECURITY

The electric utility industry is an identified critical infrastructure function with mandatory cyber security requirements under the authority of FERC. The North American Electric Reliability Corporation (NERC), which FERC certified as the nation’s Electric Reliability Organization, developed mandatory critical infrastructure protection cyber security reliability standards. AEP began participating in the NERC grid security and emergency response exercises, GridEx, in 2013 and continues to participate in the bi-yearly exercises. These efforts, led by NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation’s electric grid. The operations of AEP’s electric utility subsidiaries are subject to extensive and rigorous mandatory cyber and physical security requirements that are developed and enforced by NERC to protect grid security and reliability. AEP’s Enterprise Security program uses the National Institute of Standards and Technology Cybersecurity Framework as a guideline.

Critical cyber assets, such as data centers, power plants, transmission operations centers and business networks are protected using multiple layers of cyber security and authentication. Cyber hackers have been successful in breaching a number of very secure facilities, including federal agencies, banks and retailers. As understanding of these events develop, AEP has adopted a defense in depth approach to cyber security and continually assesses its cyber security tools and processes to determine where to strengthen its defenses. These strategies include monitoring, alerting and emergency response, forensic analysis, disaster recovery and criminal activity reporting. This approach allows AEP to deal with threats in real time.

AEP has undertaken a variety of actions to monitor and address cyber related risks. Cyber security and the effectiveness of AEP’s cyber security processes are reviewed annually with the Board of Directors and at several meetings with the Audit Committee throughout the year. AEP’s strategy for managing cyber related risks is integrated within its enterprise risk management processes. AEP enterprise security continually adjusts staff and resources in response to the evolving threat landscape. In addition, AEP maintains cyber liability insurance to cover certain damages caused by cyber incidents.

AEP’s Chief Security Officer (CSO) leads the cyber security and physical security teams and is responsible for the design, implementation and execution of AEP’s security risk management strategy, which includes cyber security. AEP operates a 24/7 Cyber Security Intelligence and Response Center (cyber security team) responsible for monitoring the AEP System for cyber risks and threats. Among other things, the CSO and the cyber security team actively monitor best practices, perform penetration testing, lead response exercises and internal campaigns and provide training and communication across the organization.

The cyber security team constantly scans the AEP System for risks and threats. AEP also continually reviews its business continuity plan to develop an effective recovery strategy that seeks to decrease response times, limit financial impacts and maintain customer confidence during any business interruption. AEP has implemented a third-party risk governance program to identify potential risks introduced through third-party relationships, such as vendors, software and hardware manufacturers or professional service providers. As warranted, AEP obtains certain contractual security guarantees and assurances with these third-party relationships to help ensure the security and safety of its information. The cyber security team works closely with a broad range of departments, including legal, regulatory, corporate communications and audit services and information technology.

The cyber security team collaborates with partners from both industry and government, and routinely participates in industry-wide programs that exchange knowledge of threats with utility peers, industry and federal agencies. AEP is an active member of a number of industry specific threat and information sharing communities including the Department of Homeland Security and the Electricity Information Sharing and Analysis Center. AEP continues to work with nonaffiliated entities to do penetration testing and to design and implement appropriate remediation strategies.

There can be no assurance, however, that these efforts will be effective to prevent interruption of services or other damages to AEP's business or operations in connection with any cyber-related incident.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

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

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

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

Regulatory Accounting

Nature of Estimates Required

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

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

Assumptions and Approach Used

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

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. See Note 5 - Effects of Regulation for additional information related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

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

Accrued unbilled revenues for the Vertically Integrated Utilities segment were $248 million and $255 million as of December 31, 2019 and 2018, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $(7) million, $(23) million and $37 million for the years ended December 31, 2019, 2018 and 2017, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $166 million and $178 million as of December 31, 2019 and 2018, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $(12) million, $(24) million and $11 million for the years ended December 31, 2019, 2018 and 2017, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Generation & Marketing segment were $75 million and $59 million as of December 31, 2019 and 2018, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $16 million, $5 million and $5 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Assumptions and Approach Used

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

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

Effect if Different Assumptions Used

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

Accounting for Derivative Instruments

Nature of Estimates Required

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

Assumptions and Approach Used

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

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

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

Effect if Different Assumptions Used

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

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

For additional information see Note 10 - Derivatives and Hedging and Note 11 - Fair Value Measurements. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for AEP's fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance and "Regulated Operations" accounting guidance, the Registrants evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. Such events or changes in circumstance include planned abandonments, probable disallowances for rate-making purposes of assets determined to be recently completed plant and assets that meet the held-for-sale criteria. The Registrants utilize a group composite method of depreciation to estimate the useful lives of long-lived assets.

An impairment evaluation of a long-lived, held and used asset may result from an abandonment, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount of the asset is not recoverable, the Registrants record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. Any impairment charge is recorded as a reduction to earnings.

Assumptions and Approach Used

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

Effect if Different Assumptions Used

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

Pension and OPEB

AEP maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Pension Plans and OPEB plans are collectively referred to as the Plans.

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

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

	Years Ended December 31,		
Net Periodic Cost (Credit)	**2019**	**2018**	**2017**
	(in millions)		
Pension Plans	$ 61.5	$ 82.9	$ 98.6
OPEB	(80.7)	(101.8)	(63.2)

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2020, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets and tax rates which affect a portion of the OPEB plans' assets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 5.75% for the Qualified Plan and 5.5% for the OPEB plans.

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

	Pension Plans		OPEB	
	2020 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2020 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	30%	7.70%	48%	7.27%
Fixed Income	54	4.18	50	3.85
Other Investments	15	7.96	—	—
Cash and Cash Equivalents	1	2.17	2	2.17
Total	100%		100%	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 5.75% for the Qualified Plan and 5.5% for the OPEB plans are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 15.81% for the year ended December 31, 2019 and an actual loss of 2.10% for the year ended December 31, 2018. The OPEB plans' assets had an actual gain of 20.93% for the year ended December 31, 2019 and an actual loss of 6.38% for the year ended December 31, 2018. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2019, AEP had cumulative gains of approximately $209 million for the Qualified Plan that remain to be recognized in the calculation of the market-related value of assets. These unrecognized market-related net actuarial gains may result in increases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with “Compensation – Retirement Benefits” accounting guidance.

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2019 under this method was 3.25% for the Qualified Plan, 3.15% for the Nonqualified Plans and 3.3% for the OPEB plans. Due to the effect of the unrecognized net actuarial losses and based on an expected rate of return on the Pension Plans’ assets of 5.75%, discount rates of 3.25% and 3.15% and various other assumptions, management estimates that the pension costs for the Pension Plans will approximate $107 million, $94 million and $81 million in 2020, 2021 and 2022, respectively. Based on an expected rate of return on the OPEB plans’ assets of 5.5%, a discount rate of 3.3% and various other assumptions, management estimates OPEB plan credits will approximate $110 million, $111 million and $112 million in 2020, 2021 and 2022, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the “Effect if Different Assumptions Used” section below.

The value of AEP’s Pension Plans’ assets increased to $5.0 billion as of December 31, 2019 from $4.7 billion as of December 31, 2018 primarily due to higher investment returns. During 2019, the Qualified Plan paid $361 million and the Nonqualified Plans paid $6 million in benefits to plan participants. The value of AEP’s OPEB plans’ assets increased to $1.8 billion as of December 31, 2019 from $1.5 billion as of December 31, 2018 primarily due to higher investment returns. The OPEB plans paid $113 million in benefits to plan participants during 2019.

Nature of Estimates Required

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

Assumptions and Approach Used

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

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

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

Effect if Different Assumptions Used

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

	Pension Plans		OPEB	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2019 Benefit Obligations				
Discount Rate	$ (258.1)	$ 283.3	$ (64.4)	$ 71.0
Compensation Increase Rate	26.3	(24.3)	NA	NA
Cash Balance Crediting Rate	71.4	(66.1)	NA	NA
Health Care Cost Trend Rate	NA	NA	15.7	(15.3)
Effect on 2019 Periodic Cost				
Discount Rate	$ (12.7)	$ 13.9	$ (3.2)	$ 3.5
Compensation Increase Rate	5.3	(4.9)	NA	NA
Cash Balance Crediting Rate	13.5	(12.4)	NA	NA
Health Care Cost Trend Rate	NA	NA	2.0	(1.9)
Expected Return on Plan Assets	(23.7)	23.7	(7.5)	7.5

NA Not applicable.

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)
Year Ended December 31, 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	(5.4)	(7.2)	(19.2)	(31.8)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	8.3	8.3
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	9.8	9.8
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(9.6)	4.6	—	(5.0)
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2019	$ 75.9	$ (103.6)	$ 163.4	135.7
Commodity Cash Flow Hedge Contracts				(125.5)
Interest Rate Cash Flow Hedge Contracts				4.6
Fair Value Hedge Contracts				14.5
Collateral Deposits				34.0
Total MTM Derivative Contract Net Assets as of December 31, 2019				$ 63.3

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

Credit Risk

Credit risk is mitigated in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses 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 December 31, 2019, credit exposure net of collateral to sub investment grade counterparties was approximately 6.5%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 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	$ 513.4	$ —	$ 513.4	2	$ 208.1
Split Rating	3.1	—	3.1	2	3.1
No External Ratings:					
Internal Investment Grade	135.8	—	135.8	4	82.2
Internal Noninvestment Grade	55.7	10.5	45.2	2	28.6
Total as of December 31, 2019	$ 708.0	$ 10.5	$ 697.5		

All exposure in the table above relates to either AEPSC or AEPEP. In addition, AEP is exposed to credit risk related to participation in RTOs. For each of the RTOs in which AEP participates, this risk is generally determined based on the proportionate share of member gross activity over a specified period of time.

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 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

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

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2019				Twelve Months Ended December 31, 2018			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.2	$ 8.5	$ 1.1	$ 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 12 months ended December 31, 2019, 2018 and 2017, a 100 basis point change in the benchmark rate on AEP’s variable rate debt would impact pretax interest expense annually by $24 million, $25 million and $28 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries (the “Company”) as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for the Effects of Cost-Based Regulation

As described in Notes 1, 4, and 5 to the consolidated financial statements, the Company's consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and matching income with its passage to customers in cost-based regulated rates. Management reviews the probability of recovery of regulatory assets and refund of regulatory liabilities at each balance sheet date, or whenever new events occur, whether influenced by regulatory commission orders, new legislation, or changes in the regulatory environment. As of December 31, 2019, there were $3.3 billion of deferred costs included in regulatory assets, $o.2 billion of which were pending final regulatory approval, and $8.5 billion of regulatory liabilities awaiting potential refund or future rate reduction, $0.5 billion of which were pending final regulatory determination.

The principal considerations for our determination that performing procedures relating to the accounting for the effects of cost-based regulation is a critical audit matter are there was significant judgment and estimation by management in the ongoing evaluation of the recovery of regulatory assets and refund of regulatory liabilities, and applying guidance contained in rate orders and other relevant evidence. This in turn led to significant audit effort and a high degree of auditor subjectivity in performing procedures and in evaluating audit evidence relating to management's judgments about the probability of recovery of regulatory assets and refund of regulatory liabilities, including estimates made to record recoveries, refunds and disallowances.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's assessment of regulatory proceedings, including the probability of recovery of regulatory assets and refund of regulatory liabilities, including management's development of the estimates made to record any recoveries, refunds and disallowances. These procedures also included, among others, evaluating the reasonableness of management's assessment of probability of future recovery for regulatory assets and refund of regulatory liabilities, and testing management's process and evaluating the reasonableness of management's estimates of amounts to be refunded or recovered and the time period over which the refunds will be made or the recoveries will occur. Testing of regulatory assets and liabilities, including those subject to pending rate cases, also involved evaluating the provisions and formulas outlined in rate orders, other regulatory correspondence, and application of regulatory precedents.

Valuation of Level 3 Risk Management Commodity Contracts

As described in Notes 1, 10 and 11 to the consolidated financial statements, the Company employs risk management commodity contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, over-the-counter swaps and options to accomplish its risk management strategies. Certain over-the-counter and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. The fair value of these risk management commodity contracts is estimated based on available market information using discounted cash flow models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. The main driver of the classification of risk management contracts within Level 3 in the fair value hierarchy is the lack of observable energy price curves in the market, which required management to apply significant judgment in developing its estimate of energy prices in future periods. Management utilized such unobservable pricing data to value its Level 3 risk management commodity contract assets and liabilities, which totaled $372.4 million and $262.5 million, as of December 31, 2019, respectively.

The principal considerations for our determination that performing procedures relating to the valuation of Level 3 risk management commodity contracts is a critical audit matter are there was significant judgment and estimation by management when developing the fair value of the commodity contracts. This in turn led to significant audit effort and a high degree of auditor subjectivity in performing procedures and in evaluating audit evidence relating to the unobservable assumptions used within management's discounted cash flow models, including projections of forward commodity prices, supply and demand levels, and future price volatility. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's valuation of the risk management commodity contracts, including controls over the assumptions used to value the Level 3 risk management commodity contracts. These procedures also included, among others, testing the data used in and management's process for developing the fair value of the Level 3 risk management commodity contracts. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the discounted cash flow models and reasonableness of the assumptions used by management, including the forward commodity prices, supply and demand levels, and future price volatility.

Acquisition of Sempra Renewables LLC

As described in Notes 7 and 17 to the consolidated financial statements, the Company completed the acquisition of Sempra Renewables LLC for net consideration of $580.4 million in 2019. Management applied significant judgment in estimating the fair value of net assets acquired, which involved the use of significant estimates and assumptions, including the pricing and terms of the existing purchase power agreements, forecasted market power prices, expected wind farm net capacity, and discount rates reflecting risk inherent in the future cash flows and future power prices.

The principal considerations for our determination that performing procedures relating to the acquisition of Sempra Renewables LLC is a critical audit matter are there was significant audit effort and a high degree of auditor subjectivity in performing procedures relating to the fair value measurement of the net assets acquired due to the significant amount of judgment used by management when developing the estimates. Significant audit effort was required in evaluating the significant assumptions relating to the future cash flows, specifically, forecasted market power prices, expected wind farm net capacity, and discount rates. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Addressing the matter involved procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the acquisition accounting, including controls over management's valuation of the acquired net assets and controls over development of the significant estimates and assumptions related to the future cash flows, specifically forecasted market power prices, expected wind farm net generation and discount rates. These procedures also included, among others, reading the purchase agreement and the related power purchase contracts, testing management's process for estimating the fair value of acquired net assets, and evaluating management's future cash flows and discount rates used to estimate the fair value of the acquired net assets, using professionals with specialized skill and knowledge to assist in doing so. Testing management's process included evaluating the appropriateness of the valuation methods and the reasonableness of the future cash flows, specifically market power prices, expected wind farm net capacity, and discount rates. Evaluating the reasonableness of forecasted market power prices involved evaluating the cost of constructing and operating a new wind plant over an assumed life in the same geographic region as of the acquisition date using third party market participant assumptions. Evaluating the reasonableness of expected wind farm net capacity involved evaluation against each wind farm's historical and expected generation. Discount rates were evaluated by considering the cost of capital of comparable businesses and other industry factors.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP's internal control over financial reporting was effective as of December 31, 2019.

PricewaterhouseCoopers LLP, AEP's independent registered public accounting firm has issued an audit report on the effectiveness of AEP's internal control over financial reporting as of December 31, 2019. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2019	**2018**	**2017**
REVENUES			
Vertically Integrated Utilities	$ 9,245.7	$ 9,556.7	$ 9,095.1
Transmission and Distribution Utilities	4,319.0	4,552.3	4,328.9
Generation & Marketing	1,721.8	1,818.1	1,771.4
Other Revenues	274.9	268.6	229.5
TOTAL REVENUES	15,561.4	16,195.7	15,424.9
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	1,940.9	2,359.4	2,346.5
Purchased Electricity for Resale	3,165.2	3,427.1	2,965.3
Other Operation	2,743.7	2,979.2	2,525.2
Maintenance	1,213.9	1,247.4	1,145.6
Asset Impairments and Other Related Charges	156.4	70.6	87.1
Gain on Sale of Merchant Generation Assets	—	—	(226.4)
Depreciation and Amortization	2,514.5	2,286.6	1,997.2
Taxes Other Than Income Taxes	1,234.5	1,142.7	1,059.4
TOTAL EXPENSES	12,969.1	13,513.0	11,899.9
OPERATING INCOME	2,592.3	2,682.7	3,525.0
Other Income (Expense):			
Other Income	26.6	18.2	34.6
Allowance for Equity Funds Used During Construction	168.4	132.5	93.7
Non-Service Cost Components of Net Periodic Benefit Cost	120.0	124.5	45.5
Gain on Sale of Equity Investment	—	—	12.4
Interest Expense	(1,072.5)	(984.4)	(895.0)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	1,834.8	1,973.5	2,816.2
Income Tax Expense (Benefit)	(12.9)	115.3	969.7
Equity Earnings of Unconsolidated Subsidiaries	72.1	73.1	82.4
NET INCOME	1,919.8	1,931.3	1,928.9
Net Income (Loss) Attributable to Noncontrolling Interests	(1.3)	7.5	16.3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,921.1	$ 1,923.8	$ 1,912.6
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	493,694,345	492,774,600	491,814,651
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.89	$ 3.90	$ 3.89
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	495,306,238	493,758,277	492,611,067
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.88	$ 3.90	$ 3.88

See Notes to Financial Statements of Registrants beginning on page 156.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Net Income	$ 1,919.8	$ 1,931.3	$ 1,928.9
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(21.1), $3.9 and $(1.4) in 2019, 2018 and 2017, Respectively	(79.4)	14.6	(2.6)
Securities Available for Sale, Net of Tax of $0, $0 and $1.9 in 2019, 2018 and 2017, Respectively	—	—	3.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(1.5), $(1.4) and $0.6 in 2019, 2018 and 2017, Respectively	(5.6)	(5.3)	1.1
Pension and OPEB Funded Status, Net of Tax of $15.3, $(8.8) and $46.7 in 2019, 2018 and 2017, Respectively	57.7	(33.0)	86.5
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(27.3)	(23.7)	88.5
TOTAL COMPREHENSIVE INCOME	1,892.5	1,907.6	2,017.4
Total Comprehensive Income (Loss) Attributable To Noncontrolling Interests	(1.3)	7.5	16.3
TOTAL OTHER COMPREHENSIVE INCOME ATTIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,893.8	$ 1,900.1	$ 2,001.1

See Notes to Financial Statements of Registrants beginning on page 156.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2016	512.0	$ 3,328.3	$ 6,332.6	$ 7,892.4	$ (156.3)	$ 23.1	$ 17,420.1
Issuance of Common Stock	0.2	1.1	11.1				12.2
Common Stock Dividends				(1,178.3) (a)		(13.6)	(1,191.9)
Other Changes in Equity			55.0			0.8	55.8
Net Income				1,912.6		16.3	1,928.9
Other Comprehensive Income					88.5		88.5
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	1.3	8.0	65.6				73.6
Common Stock Dividends				(1,251.1) (a)		(4.4)	(1,255.5)
Other Changes in Equity			21.8			1.3	23.1
ASU 2018-02 Adoption				14.0	(17.0)		(3.0)
ASU 2016-01 Adoption				11.9	(11.9)		—
Net Income				1,923.8		7.5	1,931.3
Other Comprehensive Loss					(23.7)		(23.7)
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	0.9	6.0	59.3				65.3
Common Stock Dividends				(1,345.5) (a)		(4.5)	(1,350.0)
Other Changes in Equity			(9.8) (b)			2.2	(7.6)
Acquisition of Sempra Renewables LLC						134.8	134.8
Acquisition of Santa Rita East						118.8	118.8
Net Income (Loss)				1,921.1		(1.3)	1,919.8
Other Comprehensive Loss					(27.3)		(27.3)
TOTAL EQUITY – DECEMBER 31, 2019	514.4	$ 3,343.4	$ 6,535.6	$ 9,900.9	$ (147.7)	$ 281.0	$ 19,913.2

(a) Cash dividends declared per AEP common share were $2.71, $2.53 and $2.39 for the years ended December 31, 2019, 2018 and 2017, respectively.
(b) Includes $(62) million related to a forward equity purchase contract associated with the issuance of Equity Units. See "Equity Units" section of Note 14 for additional information.

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 246.8	$ 234.1
Restricted Cash (December 31, 2019 and 2018 Amounts Include $185.8 and $210, Respectively, Related to Transition Funding, Restoration Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Santa Rita East)	185.8	210.0
Other Temporary Investments (December 31, 2019 and 2018 Amounts Include $187.8 and $152.7, Respectively, Related to EIS and Transource Energy)	202.7	159.1
Accounts Receivable:		
Customers	625.3	699.0
Accrued Unbilled Revenues	222.4	209.3
Pledged Accounts Receivable – AEP Credit	873.9	999.8
Miscellaneous	27.2	55.2
Allowance for Uncollectible Accounts	(43.7)	(36.8)
Total Accounts Receivable	1,705.1	1,926.5
Fuel	528.5	319.0
Materials and Supplies	640.7	602.1
Risk Management Assets	172.8	162.8
Regulatory Asset for Under-Recovered Fuel Costs	92.9	150.1
Margin Deposits	60.4	141.4
Prepayments and Other Current Assets	242.1	208.8
TOTAL CURRENT ASSETS	4,077.8	4,113.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	22,762.4	21,699.9
Transmission	24,808.6	21,531.0
Distribution	22,443.4	21,195.4
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	4,811.5	4,265.0
Construction Work in Progress	4,319.8	4,393.9
Total Property, Plant and Equipment	79,145.7	73,085.2
Accumulated Depreciation and Amortization	19,007.6	17,986.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	60,138.1	55,099.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,158.8	3,310.4
Securitized Assets	858.1	920.6
Spent Nuclear Fuel and Decommissioning Trusts	2,975.7	2,474.9
Goodwill	52.5	52.5
Long-term Risk Management Assets	266.6	254.0
Operating Lease Assets	957.4	—
Deferred Charges and Other Noncurrent Assets	3,407.3	2,577.4
TOTAL OTHER NONCURRENT ASSETS	11,676.4	9,589.8
TOTAL ASSETS	$ 75,892.3	$ 68,802.8

See Notes to Financial Statements of Registrants beginning on page 156.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2019 and 2018
(dollars in millions)

	December 31, 2019	December 31, 2018
CURRENT LIABILITIES		
Accounts Payable	$ 2,085.8	$ 1,874.3
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	710.0	750.0
Other Short-term Debt	2,128.3	1,160.0
Total Short-term Debt	2,838.3	1,910.0
Long-term Debt Due Within One Year (December 31, 2019 and 2018 Amounts Include $565.1 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)	1,598.7	1,698.5
Risk Management Liabilities	114.3	55.0
Customer Deposits	366.1	412.2
Accrued Taxes	1,357.8	1,218.0
Accrued Interest	243.6	231.7
Obligations Under Operating Leases	234.1	—
Regulatory Liability for Over-Recovered Fuel Costs	86.6	58.6
Other Current Liabilities	1,373.8	1,190.5
TOTAL CURRENT LIABILITIES	10,299.1	8,648.8
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2019 and 2018 Amounts Include $907 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)	25,126.8	21,648.2
Long-term Risk Management Liabilities	261.8	263.4
Deferred Income Taxes	7,588.2	7,086.5
Regulatory Liabilities and Deferred Investment Tax Credits	8,457.6	8,540.3
Asset Retirement Obligations	2,216.6	2,287.7
Employee Benefits and Pension Obligations	466.0	377.1
Obligations Under Operating Leases	734.6	—
Deferred Credits and Other Noncurrent Liabilities	719.8	782.6
TOTAL NONCURRENT LIABILITIES	45,571.4	40,985.8
TOTAL LIABILITIES	55,870.5	49,634.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	65.7	69.4
Contingently Redeemable Performance Share Awards	42.9	39.4
TOTAL MEZZANINE EQUITY	108.6	108.8

EQUITY

	2019	2018	December 31, 2019	December 31, 2018
Common Stock – Par Value – $6.50 Per Share:				
Shares Authorized	600,000,000	600,000,000		
Shares Issued	514,373,631	513,450,036		
(20,204,160 Shares were Held in Treasury as of December 31, 2019 and 2018, Respectively)			3,343.4	3,337.4
Paid-in Capital			6,535.6	6,486.1
Retained Earnings			9,900.9	9,325.3

Accumulated Other Comprehensive Income (Loss)	(147.7)	(120.4)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	19,632.2	19,028.4
Noncontrolling Interests	281.0	31.0
TOTAL EQUITY	19,913.2	19,059.4
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 75,892.3	$ 68,802.8

See Notes to Financial Statements of Registrants beginning on page 156.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
OPERATING ACTIVITIES			
Net Income	$ 1,919.8	$ 1,931.3	$ 1,928.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	2,514.5	2,286.6	1,997.2
Rockport Plant, Unit 2 Operating Lease Amortization	136.5	—	—
Deferred Income Taxes	(17.8)	104.3	901.5
Asset Impairments and Other Related Charges	156.4	70.6	87.1
Allowance for Equity Funds Used During Construction	(168.4)	(132.5)	(93.7)
Mark-to-Market of Risk Management Contracts	(29.2)	(66.4)	(23.3)
Amortization of Nuclear Fuel	89.1	113.8	129.1
Pension and Postemployment Benefit Reserves	(24.6)	(42.8)	27.8
Pension Contributions to Qualified Plan Trust	—	—	(93.3)
Property Taxes	(73.8)	(59.1)	(29.5)
Deferred Fuel Over/Under-Recovery, Net	85.2	189.7	84.4
Gain on Sale of Merchant Generation Assets	—	—	(226.4)
Recovery of Ohio Capacity Costs, Net	34.1	67.7	83.2
Refund of Global Settlement	(16.5)	(5.5)	(98.2)
Change in Other Noncurrent Assets	(97.4)	119.8	(423.9)
Change in Other Noncurrent Liabilities	(116.1)	129.0	181.7
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	247.8	145.9	28.5
Fuel, Materials and Supplies	(248.2)	20.7	17.9
Accounts Payable	5.8	36.6	(58.0)
Accrued Taxes, Net	138.9	153.2	91.9
Rockport Plant, Unit 2 Operating Lease Payments	(147.7)	—	—
Other Current Assets	70.7	10.5	(60.7)
Other Current Liabilities	(189.0)	149.8	(181.8)
Net Cash Flows from Operating Activities	4,270.1	5,223.2	4,270.4
INVESTING ACTIVITIES			
Construction Expenditures	(6,051.4)	(6,310.9)	(5,691.3)
Purchases of Investment Securities	(1,576.0)	(2,067.8)	(2,314.7)
Sales of Investment Securities	1,494.2	2,010.0	2,256.3
Acquisitions of Nuclear Fuel	(92.3)	(46.1)	(108.0)
Acquisition of Sempra Renewables LLC and Santa Rita East, net of cash and restricted cash acquired	(918.4)	—	—
Proceeds from Sale of Merchant Generation Assets	—	—	2,159.6
Other Investing Activities	(0.6)	61.2	41.7
Net Cash Flows Used for Investing Activities	(7,144.5)	(6,353.6)	(3,656.4)
FINANCING ACTIVITIES			
Issuance of Common Stock	65.3	73.6	12.2
Issuance of Long-term Debt	4,536.6	4,945.7	3,854.1
Commercial Paper and Credit Facility Borrowings	—	205.6	—
Change in Short-term Debt, Net	928.3	271.4	(74.4)
Retirement of Long-term Debt	(1,220.8)	(2,782.0)	(3,087.9)
Commercial Paper and Credit Facility Repayments	—	(205.6)	—
Make Whole Premium on Extinguishment of Long-term Debt	(5.0)	(13.5)	(46.1)
Principal Payments for Finance Lease Obligations	(70.7)	(65.1)	(67.3)
Dividends Paid on Common Stock	(1,350.0)	(1,255.5)	(1,191.9)

Other Financing Activities	(20.8)	(12.7)	(3.6)
Net Cash Flows from (Used for) Financing Activities	2,862.9	1,161.9	(604.9)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(11.5)	31.5	9.1
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	444.1	412.6	403.5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 432.6	$ 444.1	$ 412.6

See Notes to Financial Statements of Registrants beginning on page 156.

COMPANY OVERVIEW

AEP Texas was formed by the merger of TCC and TNC into AEP Utilities on December 31, 2016. The merging parties consolidated the majority of their rate structures following the completion of their 2019 base rate case. See Note 4 - Rate Matters for additional information related to the 2019 base rate case. Following the merger, AEP Utilities changed its name to AEP Texas.

AEP Texas is engaged in the transmission and distribution of electric power to approximately 1,049,000 retail customers through REPs in west, central and southern Texas. Among the principal industries served by AEP Texas are petroleum and coal products manufacturing, chemical manufacturing, oil and gas extraction, pipeline transportation and primary metal manufacturing. The territory served by AEP Texas also includes several military installations and correctional facilities. AEP Texas is a member of ERCOT. Under Texas Restructuring Legislation, AEP Texas' utility predecessors, TCC and TNC, exited the generation business and ceased serving retail load. However, AEP Texas continues as part owner in the Oklaunion Power Station operated by PSO, which management announced plans to close by October 2020 pending necessary approvals. AEP Texas consolidates AEP Texas North Generation Company, LLC, AEP Texas Central Transition Funding II LLC, AEP Texas Central Transition Funding III LLC and AEP Texas Restoration Funding LLC, its wholly-owned subsidiaries.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	11,996	12,101	11,569
Commercial	10,419	10,220	10,382
Industrial	8,882	9,053	8,964
Miscellaneous	665	646	638
Total Retail (a)	31,962	32,020	31,553

(a) 2018 and 2017 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

	Years Ended December 31,		
	2019	2018	2017
	(in degree days)		
Actual – Heating (a)	301	354	239
Normal – Heating (b)	322	325	330
Actual – Cooling (c)	2,989	2,861	2,950
Normal – Cooling (b)	2,699	2,688	2,669

(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.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$ 211.3
Changes in Gross Margin:	
Retail Margins	(28.4)
Margins from Off-system Sales	61.0
Transmission Revenues	75.8
Other Revenues	13.0
Total Change in Gross Margin	121.4
Changes in Expenses and Other:	
Other Operation and Maintenance	(72.5)
Asset Impairments and Other Related Charges	(32.5)
Depreciation and Amortization	(122.7)
Taxes Other Than Income Taxes	(8.0)
Interest Income	2.6
Allowance for Equity Funds Used During Construction	(4.8)
Non-Service Cost Components of Net Periodic Benefit Cost	(1.0)
Interest Expense	10.1
Total Change in Expenses and Other	(228.8)
Income Tax Expense (Benefit)	74.4
Year Ended December 31, 2019	$ 178.3

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** decreased $28 million primarily due to the following:
  - A $30 million decrease due to a provision for refund in the 2019 Texas Base Rate Case.
  - A $2 million decrease in weather-related usage primarily due to a 15% decrease in heating degree days, partially offset by a 4% increase in cooling degree days.

  These decreases were partially offset by:
  - A $5 million increase in weather-normalized margins primarily in the residential and commercial classes.
- **Margins from Off-system Sales** increased $61 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 $76 million primarily due to recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $13 million primarily due to securitization revenue. This increase 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 increased $73 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.
  - A $6 million increase due to a charitable contribution to the AEP Foundation.
  - A $4 million increase due to a regulatory disallowance in the 2019 Texas Base Rate Case for rate case expenses.

  These increases were partially offset by:
  - A $7 million decrease in ERCOT transmission expenses. This decrease was partially offset in Retail Margins above.
  - A $3 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.
- **Asset Impairments and Other Related Charges** increased $33 million due to regulatory disallowances in the 2019 Texas Base Rate Case.
- **Depreciation and Amortization** expenses increased $123 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 partially offset above in Margins from Off-system Sales and in Other Operation and Maintenance expenses.
  - A $47 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 $20 million increase in securitization amortizations. 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.
- **Allowance for Equity Funds Used During Construction** decreased $5 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 $10 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.
  - A $10 million decrease in expense related to securitization assets. This decrease was offset above in Other Revenues and Depreciation and Amortization expenses.

  These decreases were partially offset by:
  - A $16 million increase due to higher long-term debt balances.
  - A $3 million increase due to higher short-term debt balances.
- **Income Tax Expense (Benefit)** decreased $74 million primarily due to an increase in 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 and a decrease in pretax book income. This decrease was partially offset above in Other Operation and Maintenance expenses.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
AEP Texas Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of AEP Texas Inc. and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management assessed the effectiveness of AEP Texas' internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP Texas' internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, AEP Texas' registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit AEP Texas to provide only management's report in this annual report.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
REVENUES			
Electric Transmission and Distribution	$ 1,545.9	$ 1,486.3	$ 1,470.3
Sales to AEP Affiliates	160.5	105.2	65.7
Other Revenues	2.9	3.8	2.4
TOTAL REVENUES	1,709.3	1,595.3	1,538.4
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	31.1	38.5	20.9
Other Operation	492.0	488.9	453.1
Maintenance	158.8	89.4	75.9
Asset Impairments and Other Related Charges	32.5	—	—
Depreciation and Amortization	622.3	499.6	450.1
Taxes Other Than Income Taxes	140.6	132.6	122.3
TOTAL EXPENSES	1,477.3	1,249.0	1,122.3
OPERATING INCOME	232.0	346.3	416.1
Other Income (Expense):			
Interest Income	3.4	0.8	2.9
Allowance for Equity Funds Used During Construction	15.2	20.0	6.8
Non-Service Cost Components of Net Periodic Benefit Cost	11.3	12.3	3.6
Interest Expense	(137.2)	(147.3)	(142.3)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	124.7	232.1	287.1
Income Tax Expense (Benefit)	(53.6)	20.8	(23.4)
NET INCOME	$ 178.3	$ 211.3	$ 310.5

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

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Net Income	$ 178.3	$ 211.3	$ 310.5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0.3, $0.3 and $0.5 in 2019, 2018 and 2017, Respectively	1.0	1.0	0.9
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0, $0.1 and $0.1 in 2019, 2018 and 2017, Respectively	0.2	0.2	0.3
Pension and OPEB Funded Status, Net of Tax of $0.3, $(0.3) and $0.6 in 2019, 2018 and 2017, Respectively	1.1	(1.0)	1.1
TOTAL OTHER COMPREHENSIVE INCOME	2.3	0.2	2.3
TOTAL COMPREHENSIVE INCOME	$ 180.6	$ 211.5	$ 312.8

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 857.9	$ 814.1	$ (14.9)	$ 1,657.1
Capital Contribution from Parent	200.0			200.0
Net Income		310.5		310.5
Other Comprehensive Income			2.3	2.3
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	1,057.9	1,124.6	(12.6)	2,169.9
Capital Contribution from Parent	200.0			200.0
ASU 2018-02 Adoption		1.8	(2.7)	(0.9)
Net Income		211.3		211.3
Other Comprehensive Income			0.2	0.2
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		178.3		178.3
Other Comprehensive Income			2.3	2.3
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 1,457.9	$ 1,516.0	$ (12.8)	$ 2,961.1

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	**2018**
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.1	$ 3.1
Restricted Cash (December 31, 2019 and 2018 Amounts Include $154.7 and $156.7, Respectively, Related to Transition Funding and Restoration Funding)	154.7	156.7
Advances to Affiliates	207.2	8.0
Accounts Receivable:		
Customers	116.0	110.9
Affiliated Companies	10.1	15.0
Accrued Unbilled Revenues	68.8	70.4
Miscellaneous	0.3	1.9
Allowance for Uncollectible Accounts	(1.8)	(1.3)
Total Accounts Receivable	193.4	196.9
Fuel	5.9	8.8
Materials and Supplies	56.7	52.8
Accrued Tax Benefits	66.1	44.9
Prepayments and Other Current Assets	5.8	5.3
TOTAL CURRENT ASSETS	692.9	476.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	351.7	352.1
Transmission	4,466.5	3,683.6
Distribution	4,215.2	4,043.2
Other Property, Plant and Equipment	805.9	727.9
Construction Work in Progress	763.9	836.2
Total Property, Plant and Equipment	10,603.2	9,643.0
Accumulated Depreciation and Amortization	1,758.1	1,651.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,845.1	7,991.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	280.6	430.0
Securitized Assets (December 31, 2019 and 2018 Amounts Include $621.2 and $636.8, Respectively, Related to Transition Funding and Restoration Funding)	623.4	649.1
Deferred Charges and Other Noncurrent Assets	147.1	56.3
TOTAL OTHER NONCURRENT ASSETS	1,051.1	1,135.4
TOTAL ASSETS	$ 10,589.1	$ 9,603.7

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	**2018**
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 216.0
Accounts Payable:		
General	256.8	276.5
Affiliated Companies	35.6	30.3
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2019 and 2018 Amounts Include $281.4 and $251.1, Respectively, Related to Transition Funding and Restoration Funding)	392.1	501.1
Risk Management Liabilities	—	0.2
Accrued Taxes	84.9	75.5
Accrued Interest (December 31, 2019 and 2018 Amounts Include $7.5 and $11.3, Respectively, Related to Transition Funding and Restoration Funding)	35.7	37.3
Oklaunion Purchase Power Agreement	22.1	24.3
Obligations Under Operating Leases	12.0	—
Other Current Liabilities	188.0	98.3
TOTAL CURRENT LIABILITIES	1,027.2	1,259.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (December 31, 2019 and 2018 Amounts Include $495.4 and $540.1, Respectively, Related to Transition Funding and Restoration Funding)	4,166.3	3,380.2
Deferred Income Taxes	965.4	913.1
Regulatory Liabilities and Deferred Investment Tax Credits	1,316.9	1,344.3
Oklaunion Purchase Power Agreement	—	22.1
Obligations Under Operating Leases	71.1	—
Deferred Credits and Other Noncurrent Liabilities	81.1	104.0
TOTAL NONCURRENT LIABILITIES	6,600.8	5,763.7
TOTAL LIABILITIES	7,628.0	7,023.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	1,457.9	1,257.9
Retained Earnings	1,516.0	1,337.7
Accumulated Other Comprehensive Income (Loss)	(12.8)	(15.1)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,961.1	2,580.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,589.1	$ 9,603.7

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 178.3	$ 211.3	$ 310.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	622.3	499.6	450.1
Deferred Income Taxes	(23.5)	(16.5)	63.3
Asset Impairments and Other Related Charges	32.5	—	—
Allowance for Equity Funds Used During Construction	(15.2)	(20.0)	(6.8)
Mark-to-Market of Risk Management Contracts	(0.2)	0.7	(0.3)
Pension Contributions to Qualified Plan Trust	—	—	(8.8)
Change in Regulatory Asset – Catastrophe Reserve	44.0	(24.9)	(99.2)
Change in Other Noncurrent Assets	(34.7)	(35.4)	(49.4)
Change in Other Noncurrent Liabilities	11.3	44.9	8.8
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	3.5	(2.9)	(23.5)
Fuel, Materials and Supplies	(1.0)	(6.0)	3.2
Accounts Payable	7.5	(20.3)	30.8
Accrued Taxes, Net	(11.8)	(5.6)	(31.3)
Other Current Assets	(0.4)	0.8	0.6
Other Current Liabilities	10.8	26.2	(15.3)
Net Cash Flows from Operating Activities	823.4	651.9	632.7
INVESTING ACTIVITIES			
Construction Expenditures	(1,275.1)	(1,428.8)	(990.9)
Change in Advances to Affiliates, Net	(199.2)	103.9	(103.3)
Other Investing Activities	2.1	35.2	18.9
Net Cash Flows Used for Investing Activities	(1,472.2)	(1,289.7)	(1,075.3)
FINANCING ACTIVITIES			
Capital Contribution from Parent	200.0	200.0	200.0
Issuance of Long-term Debt – Nonaffiliated	1,070.4	494.0	749.6
Change in Advances from Affiliates, Net	(216.0)	216.0	(169.5)
Retirement of Long-term Debt – Nonaffiliated	(401.8)	(266.1)	(323.1)
Principal Payments for Finance Lease Obligations	(5.1)	(4.7)	(3.9)
Other Financing Activities	(0.7)	1.2	(0.2)
Net Cash Flows from Financing Activities	646.8	640.4	452.9
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(2.0)	2.6	10.3
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	159.8	157.2	146.9
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 157.8	$ 159.8	$ 157.2
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 148.6	$ 145.9	$ 134.6
Net Cash Paid (Received) for Income Taxes	(11.0)	7.9	(28.3)
Noncash Acquisitions Under Finance Leases	11.4	10.6	8.2
Construction Expenditures Included in Current Liabilities as of December 31,	225.5	243.1	325.7

See Notes to Financial Statements of Registrants beginning on page 156.

COMPANY OVERVIEW

AEPTCo is a holding company for seven FERC regulated transmission-only electric utilities. AEPTCo is an indirect wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP").

AEPTCo's seven wholly-owned public utility companies are (collectively referred to herein as the "State Transcos"):

- AEP Appalachian Transmission Company, Inc. ("APTCo")
- AEP Indiana Michigan Transmission Company, Inc. ("IMTCo")
- AEP Kentucky Transmission Company, Inc. ("KTCo")
- AEP Ohio Transmission Company, Inc. ("OHTCo")
- AEP West Virginia Transmission Company, Inc. ("WVTCo")
- AEP Oklahoma Transmission Company, Inc. ("OKTCo")
- AEP Southwestern Transmission Company, Inc. ("SWTCo")

AEPTCo's business activities are the development, construction and operation of transmission facilities through investments in seven wholly-owned FERC-regulated transmission only electric subsidiaries.

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of December 31,		
	2019	2018	2017
	(in millions)		
Plant In Service	$ 8,407.5	$ 6,689.8	$ 5,446.5
CWIP	1,485.7	1,578.3	1,324.0
Accumulated Depreciation	402.3	271.9	152.6
Total Transmission Property, Net	$ 9,490.9	$ 7,996.2	$ 6,617.9

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$ 315.9
Changes in Transmission Revenues:	
Transmission Revenues	245.3
Total Change in Transmission Revenues	245.3
Changes in Expenses and Other:	
Other Operation and Maintenance	(15.0)
Depreciation and Amortization	(42.1)
Taxes Other Than Income Taxes	(31.1)
Interest Income - Affiliated	0.5
Allowance for Equity Funds Used During Construction	13.7
Interest Expense	(14.2)
Total Change in Expenses and Other	(88.2)
Income Tax Expense	(33.3)
Year Ended December 31, 2019	$ 439.7

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

- **Transmission Revenues** increased $245 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $15 million primarily due to the following:
  - An $8 million increase due to continued investment in transmission assets.
  - A $7 million increase due to a charitable contribution to the AEP Foundation.
- **Depreciation and Amortization** expenses increased $42 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $31 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $14 million primarily due to the following:
  - A $15 million increase due to higher monthly 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 $14 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $33 million primarily due to higher pretax book income.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Member of
AEP Transmission Company, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of AEP Transmission Company, LLC and its subsidiaries (the “Company”) as of December 31, 2019 and 2018, and the related consolidated statements of income, of changes in member's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company’s auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of AEP Transmission Company, LLC and Subsidiaries (AEPTCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEPTCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of AEPTCo's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEPTCo's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, AEPTCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit AEPTCo to provide only management's report in this annual report.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
REVENUES			
Transmission Revenues	$ 214.6	$ 177.0	$ 138.0
Sales to AEP Affiliates	806.7	598.9	568.1
Other Revenues	0.1	0.2	0.8
TOTAL REVENUES	1,021.4	776.1	706.9
EXPENSES			
Other Operation	93.9	83.8	60.1
Maintenance	15.4	10.5	8.5
Depreciation and Amortization	176.0	133.9	95.7
Taxes Other Than Income Taxes	168.9	137.8	109.7
TOTAL EXPENSES	454.2	366.0	274.0
OPERATING INCOME	567.2	410.1	432.9
Other Income (Expense):			
Interest Income - Affiliated	3.0	2.5	1.2
Allowance for Equity Funds Used During Construction	84.3	70.6	49.0
Interest Expense	(97.4)	(83.2)	(70.2)
INCOME BEFORE INCOME TAX EXPENSE	557.1	400.0	412.9
Income Tax Expense	117.4	84.1	142.2
NET INCOME	$ 439.7	$ 315.9	$ 270.7

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Paid-in Capital	Retained Earnings	Total Member's Equity
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2016	$ 1,455.0	$ 502.6	$ 1,957.6
Capital Contribution from Member	361.6		361.6
Net Income		270.7	270.7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2017	1,816.6	773.3	2,589.9
Capital Contribution from Member	664.0		664.0
Net Income		315.9	315.9
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2018	2,480.6	1,089.2	3,569.8
Net Income		439.7	439.7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2019	$ 2,480.6	$ 1,528.9	$ 4,009.5

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	**2018**
CURRENT ASSETS		
Advances to Affiliates	$ 85.4	$ 96.9
Accounts Receivable:		
Customers	19.0	11.8
Affiliated Companies	66.1	61.0
Total Accounts Receivable	85.1	72.8
Materials and Supplies	13.8	19.0
Accrued Tax Benefits	9.3	33.4
Prepayments and Other Current Assets	3.8	3.4
TOTAL CURRENT ASSETS	197.4	225.5
TRANSMISSION PROPERTY		
Transmission Property	8,137.9	6,515.8
Other Property, Plant and Equipment	269.6	174.0
Construction Work in Progress	1,485.7	1,578.3
Total Transmission Property	9,893.2	8,268.1
Accumulated Depreciation and Amortization	402.3	271.9
TOTAL TRANSMISSION PROPERTY – NET	9,490.9	7,996.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	4.2	12.9
Deferred Property Taxes	193.5	157.9
Deferred Charges and Other Noncurrent Assets	4.8	1.6
TOTAL OTHER NONCURRENT ASSETS	202.5	172.4
TOTAL ASSETS	$ 9,890.8	$ 8,394.1

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
December 31, 2019 and 2018

	December 31, 2019	December 31, 2018
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 137.0	$ 45.4
Accounts Payable:		
General	493.4	347.2
Affiliated Companies	71.2	56.0
Long-term Debt Due Within One Year – Nonaffiliated	—	85.0
Accrued Taxes	355.6	288.9
Accrued Interest	19.2	15.9
Obligations Under Operating Leases	2.1	—
Other Current Liabilities	14.6	3.8
TOTAL CURRENT LIABILITIES	1,093.1	842.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,427.3	2,738.0
Deferred Income Taxes	817.8	704.4
Regulatory Liabilities	540.9	521.3
Obligations Under Operating Leases	1.9	—
Deferred Credits and Other Noncurrent Liabilities	0.3	18.4
TOTAL NONCURRENT LIABILITIES	4,788.2	3,982.1
TOTAL LIABILITIES	5,881.3	4,824.3
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEMBER'S EQUITY		
Paid-in Capital	2,480.6	2,480.6
Retained Earnings	1,528.9	1,089.2
TOTAL MEMBER'S EQUITY	4,009.5	3,569.8
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 9,890.8	$ 8,394.1

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 439.7	$ 315.9	$ 270.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	176.0	133.9	95.7
Deferred Income Taxes	91.3	98.9	271.5
Allowance for Equity Funds Used During Construction	(84.3)	(70.6)	(49.0)
Property Taxes	(35.6)	(32.9)	(22.8)
Change in Other Noncurrent Assets	9.6	14.6	11.0
Change in Other Noncurrent Liabilities	(8.1)	17.4	27.5
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(5.4)	36.7	(30.4)
Materials and Supplies	5.2	(5.4)	(8.6)
Accounts Payable	37.6	(7.5)	23.0
Accrued Taxes, Net	90.8	73.4	16.3
Accrued Interest	3.3	0.9	4.5
Other Current Assets	(0.3)	(0.3)	(4.8)
Other Current Liabilities	(11.2)	(26.4)	0.2
Net Cash Flows from Operating Activities	708.6	548.6	604.8
INVESTING ACTIVITIES			
Construction Expenditures	(1,410.1)	(1,526.4)	(1,513.4)
Change in Advances to Affiliates, Net	11.5	49.4	(79.2)
Acquisitions of Assets	(9.4)	(37.4)	(9.1)
Other Investing Activities	4.8	1.1	6.1
Net Cash Flows Used for Investing Activities	(1,403.2)	(1,513.3)	(1,595.6)
FINANCING ACTIVITIES			
Capital Contributions from Member	—	664.0	361.6
Issuance of Long-term Debt – Nonaffiliated	688.0	321.0	617.6
Change in Advances from Affiliates, Net	91.6	29.7	11.6
Retirement of Long-term Debt – Nonaffiliated	(85.0)	(50.0)	—
Net Cash Flows from Financing Activities	694.6	964.7	990.8
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	$ 90.6	$ 80.2	$ 62.4
Net Cash Paid (Received) for Income Taxes	1.5	(30.7)	(107.3)
Noncash Acquisitions Under Finance Leases	—	—	0.2
Construction Expenditures Included in Current Liabilities as of December 31,	472.7	345.0	485.0

See Notes to Financial Statements of Registrants beginning on page 156.

COMPANY OVERVIEW

As a public utility, APCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 956,000 retail customers in its service territory in southwestern Virginia and southern West Virginia. APCo consolidates Cedar Coal Company, Central Appalachian Coal Company, Southern Appalachian Coal Company and Appalachian Consumer Rate Relief Funding LLC, its wholly-owned subsidiaries. APCo sells power at wholesale to municipalities. APCo shares its off-system sales margins with its Virginia customers. APCo's off-system sales margins are returned to APCo's West Virginia customers through the ENEC clause.

Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. APCo shares in the revenues and expenses associated with these risk management activities with the member companies.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including APCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

APCo is jointly and severally liable for activity conducted by AEPSC on behalf of APCo, I&M, KPCo and WPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in millions of KWhs)		
Retail:			
Residential	11,253	11,871	10,701
Commercial	6,365	6,581	6,434
Industrial	9,546	9,576	9,622
Miscellaneous	857	866	836
Total Retail (a)	28,021	28,894	27,593
Wholesale	3,085	2,693	3,089
Total KWhs	31,106	31,587	30,682

(a) 2018 and 2017 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

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in degree days)		
Actual – Heating (a)	2,057	2,400	1,848
Normal – Heating (b)	2,224	2,230	2,235
Actual – Cooling (c)	1,597	1,587	1,249
Normal – Cooling (b)	1,221	1,208	1,201

(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.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$	367.8
Changes in Gross Margin:		
Retail Margins		12.2
Margins from Off-system Sales		1.9
Transmission Revenues		34.3
Other Revenues		2.7
Total Change in Gross Margin		51.1
Changes in Expenses and Other:		
Other Operation and Maintenance		5.5
Asset Impairment and Other Related Charges		(92.9)
Depreciation and Amortization		(38.4)
Taxes Other Than Income Taxes		(11.5)
Interest Income		0.6
Carrying Costs Income		(1.3)
Allowance for Equity Funds Used During Construction		3.4
Non-Service Cost Components of Net Periodic Benefit Cost		(0.9)
Interest Expense		(10.2)
Total Change in Expenses and Other		(145.7)
Income Tax Expense (Benefit)		33.1
Year Ended December 31, 2019	$	306.3

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 $12 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 $30 million increase in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $23 million increase primarily due to revenue from rate riders in West Virginia. This increase was offset in other expense items below.
  - An $18 million increase due to base rate increases in West Virginia implemented in March 2019.
  - A $10 million increase due to 2018 Virginia legislation which increased non-recoverable fuel expense in the prior year.

  These increases were partially offset by:
  - A $95 million decrease due to customer refunds related to Tax Reform. This decrease was partially offset in Income Tax Expense (Benefit) below.
  - A $38 million decrease in weather-related usage primarily driven by a 14% decrease in heating degree days.
  - A $14 million decrease in weather-normalized margins occurring across all retail classes.
- **Transmission Revenues** increased $34 million primarily due to the following:
  - An $18 million increase due to an increase in the net revenue requirement.
  - A $16 million increase 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 $6 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. This decrease was partially offset in Retail Margins above and Income Tax Expense (Benefit) below.
  - A $14 million decrease in maintenance expense at various generation plants.
  - An $11 million decrease in storm-related expenses.
  - 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.
  - A $6 million decrease in estimated expenses for claims related to asbestos exposure.
  - A $5 million decrease in vegetation management services.

  These decreases were partially offset by:
  - A $41 million increase in recoverable PJM transmission expenses. This increase was partially offset within Retail Margins above.
  - A $17 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 $9 million increase due to a charitable contribution to the AEP Foundation.
- **Asset Impairments and Other Related Charges** increased $93 million due to a pretax expense recorded in 2019 related to previously retired coal-fired assets.
- **Depreciation and Amortization** expenses increased $38 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 $12 million primarily due to the following:
  - A $9 million increase in West Virginia business and occupational taxes.
  - A $3 million increase in property taxes due to additional investments in utility plant.
- **Allowance for Equity Funds Used During Construction** increased $3 million due to an increase in construction activity.
- **Interest Expense** increased $10 million primarily due to higher long-term debt balances.
- **Income Tax Expense (Benefit)** decreased $33 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 and Other Operation and Maintenance expenses above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Appalachian Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management assessed the effectiveness of APCo's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded APCo's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, APCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit APCo to provide only management's report in this annual report.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,708.2	$ 2,777.1	$ 2,749.0
Sales to AEP Affiliates	205.3	181.4	172.0
Other Revenues	11.2	9.0	13.2
TOTAL REVENUES	2,924.7	2,967.5	2,934.2
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	607.5	588.9	597.3
Purchased Electricity for Resale	391.0	503.5	357.6
Other Operation	567.6	511.6	503.1
Maintenance	255.4	316.9	251.6
Asset Impairments and Other Related Charges	92.9	—	—
Depreciation and Amortization	466.8	428.4	407.9
Taxes Other Than Income Taxes	146.2	134.7	126.4
TOTAL EXPENSES	2,527.4	2,484.0	2,243.9
OPERATING INCOME	397.3	483.5	690.3
Other Income (Expense):			
Interest Income	2.4	1.8	1.4
Carrying Costs Income	—	1.3	1.4
Allowance for Equity Funds Used During Construction	16.6	13.2	9.2
Non-Service Cost Components of Net Periodic Benefit Cost	17.0	17.9	5.2
Interest Expense	(205.0)	(194.8)	(190.9)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	228.3	322.9	516.6
Income Tax Expense (Benefit)	(78.0)	(44.9)	185.3
NET INCOME	$ 306.3	$ 367.8	$ 331.3

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

See Notes to Financial Statements of Registrants beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
Net Income	$ 306.3	$ 367.8	$ 331.3
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(0.2), $(0.2) and $(0.4) in 2019, 2018 and 2017, Respectively	(0.9)	(0.9)	(0.7)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.7), $(0.8) and $(0.6) in 2019, 2018 and 2017, Respectively	(2.5)	(3.1)	(1.2)
Pension and OPEB Funded Status, Net of Tax of $3.6, $(0.7) and $6.3 in 2019, 2018 and 2017, Respectively	13.4	(2.6)	11.6
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	10.0	(6.6)	9.7
TOTAL COMPREHENSIVE INCOME	$ 316.3	$ 361.2	$ 341.0

See Notes to Financial Statements of Registrants beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 260.4	$ 1,828.7	$ 1,502.8	$ (8.4)	$ 3,583.5
Common Stock Dividends			(120.0)		(120.0)
Net Income			331.3		331.3
Other Comprehensive Income				9.7	9.7
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	260.4	1,828.7	1,714.1	1.3	3,804.5
Common Stock Dividends			(160.0)		(160.0)
ASU 2018-02 Adoption			0.1	0.3	0.4
Net Income			367.8		367.8
Other Comprehensive Loss				(6.6)	(6.6)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	260.4	1,828.7	1,922.0	(5.0)	4,006.1
Common Stock Dividends			(150.0)		(150.0)
Net Income			306.3		306.3
Other Comprehensive Income				10.0	10.0
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 260.4	$ 1,828.7	$ 2,078.3	$ 5.0	$ 4,172.4

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	**2018**
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.3	$ 4.2
Restricted Cash for Securitized Funding	23.5	25.6
Advances to Affiliates	22.1	23.0
Accounts Receivable:		
Customers	129.0	146.5
Affiliated Companies	64.3	73.4
Accrued Unbilled Revenues	59.7	63.5
Miscellaneous	0.5	2.3
Allowance for Uncollectible Accounts	(2.6)	(2.3)
Total Accounts Receivable	250.9	283.4
Fuel	149.7	61.3
Materials and Supplies	105.2	100.1
Risk Management Assets	39.4	57.2
Regulatory Asset for Under-Recovered Fuel Costs	42.5	99.6
Prepayments and Other Current Assets	64.0	44.3
TOTAL CURRENT ASSETS	700.6	698.7
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,563.7	6,509.6
Transmission	3,584.1	3,317.7
Distribution	4,201.7	3,989.4
Other Property, Plant and Equipment	571.3	485.8
Construction Work in Progress	593.4	490.2
Total Property, Plant and Equipment	15,514.2	14,792.7
Accumulated Depreciation and Amortization	4,432.3	4,124.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	11,081.9	10,668.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	457.2	475.8
Securitized Assets	234.7	258.7
Long-term Risk Management Assets	0.1	0.9
Operating Lease Assets	78.5	—
Deferred Charges and Other Noncurrent Assets	215.3	188.1
TOTAL OTHER NONCURRENT ASSETS	985.8	923.5
TOTAL ASSETS	$ 12,768.3	$ 12,290.5

See Notes to Financial Statements of Registrants beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2019 and 2018

	December 31,	
	2019	2018
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 236.7	$ 205.6
Accounts Payable:		
General	307.8	263.8
Affiliated Companies	92.5	84.0
Long-term Debt Due Within One Year - Nonaffiliated	215.6	430.7
Risk Management Liabilities	1.9	0.4
Customer Deposits	85.8	88.4
Accrued Taxes	99.6	89.3
Obligations Under Operating Leases	15.2	—
Other Current Liabilities	170.9	191.8
TOTAL CURRENT LIABILITIES	1,226.0	1,354.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,148.2	3,631.9
Long-term Risk Management Liabilities	—	0.2
Deferred Income Taxes	1,680.8	1,625.8
Regulatory Liabilities and Deferred Investment Tax Credits	1,268.7	1,449.7
Asset Retirement Obligations	102.1	107.1
Employee Benefits and Pension Obligations	50.9	57.1
Obligations Under Operating Leases	64.0	—
Deferred Credits and Other Noncurrent Liabilities	55.2	58.6
TOTAL NONCURRENT LIABILITIES	7,369.9	6,930.4
TOTAL LIABILITIES	8,595.9	8,284.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
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	2,078.3	1,922.0
Accumulated Other Comprehensive Income (Loss)	5.0	(5.0)
TOTAL COMMON SHAREHOLDER'S EQUITY	4,172.4	4,006.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,768.3	$ 12,290.5

See Notes to Financial Statements of Registrants beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 306.3	$ 367.8	$ 331.3
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	466.8	428.4	407.9
Deferred Income Taxes	(126.2)	(16.8)	171.5
Asset Impairments and Other Related Charges	92.9	—	—
Allowance for Equity Funds Used During Construction	(16.6)	(13.2)	(9.2)
Mark-to-Market of Risk Management Contracts	19.9	(33.0)	(23.1)
Pension Contributions to Qualified Plan Trust	—	—	(10.2)
Deferred Fuel Over/Under-Recovery, Net	57.1	(10.8)	(20.5)
Change in Other Noncurrent Assets	(38.2)	58.1	11.4
Change in Other Noncurrent Liabilities	(40.3)	(4.8)	11.9
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	35.7	33.6	(28.0)
Fuel, Materials and Supplies	(93.4)	27.8	22.3
Accounts Payable	37.7	(13.3)	37.5
Accrued Taxes, Net	(10.2)	(13.2)	(12.7)
Other Current Assets	15.4	(6.1)	0.7
Other Current Liabilities	(45.5)	42.1	(10.8)
Net Cash Flows from Operating Activities	661.4	846.6	880.0
INVESTING ACTIVITIES			
Construction Expenditures	(862.6)	(780.7)	(818.1)
Change in Advances to Affiliates, Net	0.9	0.5	0.6
Other Investing Activities	24.3	10.8	15.2
Net Cash Flows Used for Investing Activities	(837.4)	(769.4)	(802.3)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	478.2	203.2	320.9
Change in Advances from Affiliates, Net	31.1	19.6	106.4
Retirement of Long-term Debt – Nonaffiliated	(180.5)	(124.0)	(377.9)
Principal Payments for Finance Lease Obligations	(6.7)	(6.9)	(6.9)
Dividends Paid on Common Stock	(150.0)	(160.0)	(120.0)
Other Financing Activities	0.9	1.5	0.5
Net Cash Flows from (Used for) Financing Activities	173.0	(66.6)	(77.0)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(3.0)	10.6	0.7
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	29.8	19.2	18.5
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 26.8	$ 29.8	$ 19.2
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 190.7	$ 182.0	$ 183.6
Net Cash Paid (Received) for Income Taxes	63.0	(13.0)	31.2
Noncash Acquisitions Under Finance Leases	8.8	5.5	3.5
Construction Expenditures Included in Current Liabilities as of December 31,	149.7	134.4	126.3

See Notes to Financial Statements of Registrants beginning on page 156.

COMPANY OVERVIEW

As a public utility, I&M engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 599,000 retail customers in its service territory in northern and eastern Indiana and southwestern Michigan. I&M consolidates Blackhawk Coal Company and Price River Coal Company, its wholly-owned subsidiaries. I&M also consolidates DCC Fuel. I&M sells power at wholesale to municipalities and electric cooperatives. I&M's River Transportation Division provides barging services to affiliates and nonaffiliated companies. The revenues from barging represent the majority of other revenues. I&M shares off-system sales margins with its customers.

Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. I&M shares in the revenues and expenses associated with these risk management activities with the member companies.

AEGCo holds a 50% interest in each of the Rockport Plant units and is entitled to 50% of the capacity and associated energy from each unit. Under unit power agreements approved by the FERC, I&M and KPCo purchase approximately 920 MWs and 390 MWs, respectively, of the output from AEGCo's 50% share of the Rockport Plant.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including I&M, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

I&M is jointly and severally liable for activity conducted by AEPSC on behalf of APCo, I&M, KPCo and WPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in millions of KWhs)		
Retail:			
Residential	5,409	5,731	5,311
Commercial	4,685	4,851	4,785
Industrial	7,589	7,836	7,781
Miscellaneous	69	71	70
Total Retail (a)	17,752	18,489	17,947
Wholesale	8,268	10,873	11,202
Total KWhs	26,020	29,362	29,149

(a) 2018 and 2017 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

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in degree days)		
Actual – Heating (a)	3,782	3,886	3,213
Normal – Heating (b)	3,740	3,747	3,758
Actual – Cooling (c)	940	1,132	792
Normal – Cooling (b)	849	849	846

(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.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$	261.3
Changes in Gross Margin:		
Retail Margins		102.9
Margins from Off-system Sales		(10.3)
Transmission Revenues		(13.7)
Other Revenues		(2.7)
Total Change in Gross Margin		76.2
Changes in Expenses and Other:		
Other Operation and Maintenance		(48.9)
Depreciation and Amortization		(57.5)
Taxes Other Than Income Taxes		(6.2)
Other Income		(1.0)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.4)
Interest Expense		6.2
Total Change in Expenses and Other		(107.8)
Income Tax Expense (Benefit)		39.7
Year Ended December 31, 2019	$	269.4

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 $103 million primarily due to the following:
  - A $112 million increase from rate proceedings, inclusive of a $24 million decrease due to the impact of Tax Reform. This increase was partially offset in other expense items below.
  - A $23 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 $28 million decrease in weather-normalized margins.
  - A $23 million decrease in weather-related usage primarily due to a 17% decrease in cooling degree days and a 3% decrease in heating degree days.
- **Margins from Off-system Sales** decreased $10 million primarily due to mid-year 2018 changes in the Indiana OSS sharing mechanism.
- **Transmission Revenues** decreased $14 million primarily due to the 2018 PJM Transmission formula rate true-up.
- **Other Revenues** decreased $3 million primarily due to a decrease in barging revenues by River Transportation Division. This decrease was partially offset in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses increased $49 million primarily due to the following:
    - A $47 million increase in transmission expenses primarily due to PJM transmission services including the annual formula rate true-up. This increase was partially offset in Retail Margins above.
    - A $9 million increase due to a charitable contribution to the AEP Foundation.
    - A $5 million increase in insurance and rate case expenses. This increase was partially offset in Retail Margins above.
    - A $5 million increase in customer service expenses primarily due to demand-side management expenses. This increase was partially offset in Retail Margins above.

  These increases were partially offset by:
    - A $9 million decrease in steam generation expenses at Rockport Plant primarily due to a decrease in various maintenance activities, employee-related expenses and amortization of terminated Indiana generation riders, partially offset by the NSR settlement in 2019. This net decrease was partially offset in Retail Margins above.
    - A $9 million decrease in generation expenses at Cook Plant primarily due to a decrease in various maintenance activities.
- **Depreciation and Amortization** expenses increased $58 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 $6 million primarily due to the reissuance of long-term debt at lower interest rates in 2018, partially offset by higher long-term debt balances.
- **Income Tax Expense (Benefit)** decreased $40 million primarily due to increased amortization of Excess ADIT not subject to normalization requirements, a decrease in state tax expense and a decrease in pretax book income. This decrease was partially offset in Gross Margin above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Indiana Michigan Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Indiana Michigan Power Company and Subsidiaries (I&M) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. I&M's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of I&M's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded I&M's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, I&M's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit I&M to provide only management's report in this annual report.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,222.1	$ 2,272.6	$ 2,042.5
Sales to AEP Affiliates	10.5	22.1	1.8
Other Revenues - Affiliated	63.4	63.4	62.6
Other Revenues - Nonaffiliated	10.7	12.6	14.3
TOTAL REVENUES	2,306.7	2,370.7	2,121.2
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	190.6	318.3	295.1
Purchased Electricity for Resale	232.3	221.8	152.2
Purchased Electricity from AEP Affiliates	214.9	237.9	223.9
Other Operation	641.2	585.4	591.3
Maintenance	231.2	238.1	208.4
Depreciation and Amortization	350.6	293.1	210.9
Taxes Other Than Income Taxes	105.1	98.9	92.2
TOTAL EXPENSES	1,965.9	1,993.5	1,774.0
OPERATING INCOME	340.8	377.2	347.2
Other Income (Expense):			
Other Income	18.2	19.2	25.6
Non-Service Cost Components of Net Periodic Benefit Cost	17.7	18.1	6.1
Interest Expense	(117.9)	(124.1)	(110.8)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	258.8	290.4	268.1
Income Tax Expense (Benefit)	(10.6)	29.1	81.4
NET INCOME	$ 269.4	$ 261.3	$ 186.7

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

See Notes to Financial Statements of Registrants beginning on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
Net Income	$ 269.4	$ 261.3	$ 186.7
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0.4, $0.4 and $0.7 in 2019, 2018 and 2017, Respectively	1.6	1.6	1.3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0, $0 and $0 in 2019, 2018 and 2017, Respectively	(0.2)	—	—
Pension and OPEB Funded Status, Net of Tax of $0.2, $(0.2) and $1.5 in 2019, 2018 and 2017, Respectively	0.8	(0.6)	2.8
TOTAL OTHER COMPREHENSIVE INCOME	2.2	1.0	4.1
TOTAL COMPREHENSIVE INCOME	$ 271.6	$ 262.3	$ 190.8

See Notes to Financial Statements of Registrants beginning on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 56.6	$ 980.9	$ 1,130.5	$ (16.2)	$ 2,151.8
Common Stock Dividends			(125.0)		(125.0)
Net Income			186.7		186.7
Other Comprehensive Income				4.1	4.1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	56.6	980.9	1,192.2	(12.1)	2,217.6
Common Stock Dividends			(124.7)		(124.7)
ASU 2018-02 Adoption			0.3	(2.7)	(2.4)
Net Income			261.3		261.3
Other Comprehensive Income				1.0	1.0
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	56.6	980.9	1,329.1	(13.8)	2,352.8
Common Stock Dividends			(80.0)		(80.0)
Net Income			269.4		269.4
Other Comprehensive Income				2.2	2.2
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 56.6	$ 980.9	$ 1,518.5	$ (11.6)	$ 2,544.4

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.0	$ 2.4
Advances to Affiliates	13.2	12.7
Accounts Receivable:		
Customers	53.6	63.1
Affiliated Companies	53.7	75.0
Accrued Unbilled Revenues	2.5	3.6
Miscellaneous	0.3	1.4
Allowance for Uncollectible Accounts	(0.6)	(0.1)
Total Accounts Receivable	109.5	143.0
Fuel	56.2	37.3
Materials and Supplies	171.3	167.3
Risk Management Assets	9.8	8.6
Accrued Tax Benefits	—	26.6
Regulatory Asset for Under-Recovered Fuel Costs	3.0	—
Accrued Reimbursement of Spent Nuclear Fuel Costs	24.0	7.9
Prepayments and Other Current Assets	14.0	24.6
TOTAL CURRENT ASSETS	403.0	430.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,099.7	4,887.2
Transmission	1,641.8	1,576.8
Distribution	2,437.6	2,249.7
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	632.6	583.8
Construction Work in Progress	382.3	465.3
Total Property, Plant and Equipment	10,194.0	9,762.8
Accumulated Depreciation, Depletion and Amortization	3,294.3	3,151.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,899.7	6,611.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	482.1	512.5
Spent Nuclear Fuel and Decommissioning Trusts	2,975.7	2,474.9
Long-term Risk Management Assets	0.1	0.6
Operating Lease Assets	294.9	—
Deferred Charges and Other Noncurrent Assets	181.9	193.0
TOTAL OTHER NONCURRENT ASSETS	3,934.7	3,181.0
TOTAL ASSETS	$ 11,237.4	$ 10,222.6

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	**2018**
CURRENT LIABILITIES		
Advances from Affiliates	$ 114.4	$ 1.1
Accounts Payable:		
General	169.4	174.7
Affiliated Companies	68.4	70.2
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2019 and 2018 Amounts Include $86.1 and $76.8 Respectively, Related to DCC Fuel)	139.7	155.4
Risk Management Liabilities	0.5	0.3
Customer Deposits	39.4	38.0
Accrued Taxes	112.4	90.7
Accrued Interest	36.2	37.3
Obligations Under Operating Leases	87.3	—
Regulatory Liability for Over-Recovered Fuel Costs	6.1	27.4
Other Current Liabilities	109.6	103.0
TOTAL CURRENT LIABILITIES	883.4	698.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,910.5	2,880.0
Long-term Risk Management Liabilities	—	0.1
Deferred Income Taxes	979.7	948.0
Regulatory Liabilities and Deferred Investment Tax Credits	1,891.4	1,574.5
Asset Retirement Obligations	1,748.6	1,681.3
Obligations Under Operating Leases	211.6	—
Deferred Credits and Other Noncurrent Liabilities	67.8	87.8
TOTAL NONCURRENT LIABILITIES	7,809.6	7,171.7
TOTAL LIABILITIES	8,693.0	7,869.8
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
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	1,518.5	1,329.1
Accumulated Other Comprehensive Income (Loss)	(11.6)	(13.8)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,544.4	2,352.8
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 11,237.4	$ 10,222.6

See Notes to Financial Statements of Registrants beginning on page 156.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 269.4	$ 261.3	$ 186.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	350.6	293.1	210.9
Rockport Plant, Unit 2 Operating Lease Amortization	69.2	—	—
Deferred Income Taxes	(52.7)	(42.9)	200.7
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(26.4)	29.2	8.5
Allowance for Equity Funds Used During Construction	(19.4)	(11.9)	(11.1)
Mark-to-Market of Risk Management Contracts	(0.6)	(4.1)	(2.3)
Amortization of Nuclear Fuel	89.1	113.8	129.1
Pension Contributions to Qualified Plan Trust	—	—	(13.0)
Deferred Fuel Over/Under-Recovery, Net	(24.3)	39.7	13.7
Change in Other Noncurrent Assets	8.3	(36.5)	(101.1)
Change in Other Noncurrent Liabilities	33.7	72.1	37.4
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	35.4	4.8	(1.1)
Fuel, Materials and Supplies	(22.4)	(11.2)	(7.5)
Accounts Payable	3.6	(14.1)	17.6
Accrued Taxes, Net	48.3	41.2	(16.6)
Rockport Plant, Unit 2 Operating Lease Payments	(73.9)	—	—
Other Current Assets	11.2	1.5	14.5
Other Current Liabilities	(13.9)	(10.3)	(5.1)
Net Cash Flows from Operating Activities	685.2	725.7	661.3
INVESTING ACTIVITIES			
Construction Expenditures	(585.9)	(568.5)	(648.5)
Change in Advances to Affiliates, Net	(0.5)	(0.3)	0.1
Purchases of Investment Securities	(1,531.0)	(2,064.7)	(2,300.5)
Sales of Investment Securities	1,473.0	2,010.0	2,256.3
Acquisitions of Nuclear Fuel	(92.3)	(46.1)	(108.0)
Other Investing Activities	16.6	14.8	9.7
Net Cash Flows Used for Investing Activities	(720.1)	(654.8)	(790.9)
FINANCING ACTIVITIES			
Issuance of Long-term Debt - Nonaffiliated	123.3	1,168.1	530.1
Change in Advances from Affiliates, Net	113.3	(210.5)	(3.6)
Retirement of Long-term Debt - Nonaffiliated	(117.1)	(884.9)	(260.7)
Principal Payments for Finance Lease Obligations	(5.7)	(8.8)	(12.0)
Dividends Paid on Common Stock	(80.0)	(124.7)	(125.0)
Other Financing Activities	0.7	(9.0)	0.9
Net Cash Flows from (Used for) Financing Activities	34.5	(69.8)	129.7
Net Increase (Decrease) in Cash and Cash Equivalents	(0.4)	1.1	0.1
Cash and Cash Equivalents at Beginning of Period	2.4	1.3	1.2
Cash and Cash Equivalents at End of Period	$ 2.0	$ 2.4	$ 1.3
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 111.9	$ 116.9	$ 94.8
Net Cash Paid (Received) for Income Taxes	3.4	32.6	(89.9)

Noncash Acquisitions Under Finance Leases	11.9	5.8	7.1
Construction Expenditures Included in Current Liabilities as of December 31,	86.0	93.0	88.5
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	0.1	4.0	—
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	0.3	2.2	2.6

See Notes to Financial Statements of Registrants beginning on page 156.

COMPANY OVERVIEW

As a public utility, OPCo engages in the transmission and distribution of power to 1,494,000 retail customers in the northwestern, central, eastern and southern sections of Ohio. Effective January 2014, OPCo purchases power from both affiliated and nonaffiliated entities, subject to auction requirements and PUCO approval, to meet the energy and capacity needs of its remaining SSO customers. OPCo consolidates Ohio Phase-in-Recovery Funding LLC, its wholly-owned subsidiary. The Ohio Phase-in-Recovery Funding LLC securitization bonds matured in July 2019.

AEPSC conducts gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including OPCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	14,411	14,940	13,539
Commercial	14,599	14,655	14,342
Industrial	14,407	14,857	14,709
Miscellaneous	114	115	119
Total Retail (a)(b)	43,531	44,567	42,709
Wholesale (c)	2,335	2,441	2,387
Total KWhs	45,866	47,008	45,096

(a) 2018 and 2017 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 into PJM.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2019	2018	2017
	(in degree days)		
Actual – Heating (a)	3,071	3,357	2,709
Normal – Heating (b)	3,208	3,215	3,225
Actual – Cooling (c)	1,224	1,402	1,002
Normal – Cooling (b)	992	980	974

(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.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$	325.5
Changes in Gross Margin:		
Retail Margins		(36.8)
Margins from Off-system Sales		(30.5)
Transmission Revenues		9.8
Other Revenues		6.9
Total Change in Gross Margin		(50.6)
Changes in Expenses and Other:		
Other Operation and Maintenance		34.6
Depreciation and Amortization		18.8
Taxes Other Than Income Taxes		(21.4)
Interest Income		(0.2)
Carrying Costs Income		(0.7)
Allowance for Equity Funds Used During Construction		8.4
Non-Service Cost Components of Net Periodic Benefit Cost		(0.9)
Interest Expense		(5.5)
Total Change in Expenses and Other		33.1
Income Tax Expense		(10.9)
Year Ended December 31, 2019	$	297.1

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 $37 million primarily due to the following:
  - A $103 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 $25 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 $22 million decrease in revenues associated with a vegetation management rider. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $21 million net decrease in margin for the Phase-In-Recovery Rider including associated amortizations which ended in the first quarter of 2019.
  - A $21 million net decrease in margin for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $15 million decrease in usage primarily in the residential and commercial classes.

  These decreases were partially offset by:
  - A $58 million increase due to a reversal of a regulatory provision.
  - A $41 million increase in revenues associated with smart grid riders. This increase was partially offset in other expense items below.
  - 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 below.
  - A $30 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.
  - An $11 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 $31 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 $10 million primarily due to 2018 provisions for refunds, partially offset by the annual PJM Transmission formula rate true-up.
- **Other Revenues** increased $7 million primarily due to distribution connection fees and pole attachment revenues.

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

- **Other Operation and Maintenance** expenses decreased $35 million primarily due to the following:
  - A $107 million decrease in recoverable PJM expenses. This decrease was offset in Gross Margin above.
  - An $11 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 $68 million increase in PJM expenses primarily related to the annual formula rate true-up.
  - An $11 million increase in Energy Efficiency/Peak Demand Reduction expenses. This increase was offset in Retail Margins above.
  - A $5 million increase due to a charitable contribution to the AEP Foundation.
- **Depreciation and Amortization** expenses decreased $19 million primarily due to the following:
  - A $26 million decrease in recoverable DIR depreciation expense. This decrease was partially offset in Retail Margins above.
  - A $23 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.

  These decreases were partially offset by:
  - A $21 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - An $11 million increase due to lower deferred equity amortizations associated with the Deferred Asset Phase-In-Recovery Rider which ended in the second quarter of 2019.
- **Taxes Other Than Income Taxes** increased $21 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 $8 million primarily due to adjustments that resulted from 2019 FERC audit findings.
- **Interest Expense** increased $6 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $11 million primarily due to decreased amortization of Excess ADIT not subject to normalization requirements. This increase was partially offset in Retail Margins above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Ohio Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Ohio Power Company and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management assessed the effectiveness of OPCo's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded OPCo's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, OPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit OPCo to provide only management's report in this annual report.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Electricity, Transmission and Distribution	$ 2,759.5	$ 3,033.8	$ 2,853.5
Sales to AEP Affiliates	27.3	21.0	24.4
Other Revenues	10.8	8.6	6.0
TOTAL REVENUES	2,797.6	3,063.4	2,883.9
EXPENSES			
Purchased Electricity for Resale	607.3	684.6	705.9
Purchased Electricity from AEP Affiliates	156.0	135.3	108.5
Amortization of Generation Deferrals	65.3	223.9	229.2
Other Operation	742.6	771.3	516.0
Maintenance	150.1	156.0	141.2
Depreciation and Amortization	240.9	259.7	225.9
Taxes Other Than Income Taxes	434.2	412.8	391.5
TOTAL EXPENSES	2,396.4	2,643.6	2,318.2
OPERATING INCOME	401.2	419.8	565.7
Other Income (Expense):			
Interest Income	3.2	3.4	4.9
Carrying Costs Income	1.0	1.7	3.6
Allowance for Equity Funds Used During Construction	18.2	9.8	6.4
Non-Service Cost Components of Net Periodic Benefit Cost	14.6	15.5	4.5
Interest Expense	(106.2)	(100.7)	(101.9)
INCOME BEFORE INCOME TAX EXPENSE	332.0	349.5	483.2
Income Tax Expense	34.9	24.0	159.3
NET INCOME	$ 297.1	$ 325.5	$ 323.9

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

See Notes to Financial Statements of Registrants beginning on page 156.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
Net Income	$ 297.1	$ 325.5	$ 323.9
OTHER COMPREHENSIVE LOSS, NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(0.3), $(0.4) and $(0.6) in 2019, 2018 and 2017, Respectively	(1.0)	(1.3)	(1.1)
TOTAL COMPREHENSIVE INCOME	$ 296.1	$ 324.2	$ 322.8

See Notes to Financial Statements of Registrants beginning on page 156.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 321.2	$ 838.8	$ 954.5	$ 3.0	$ 2,117.5
Common Stock Dividends			(130.0)		(130.0)
Net Income			323.9		323.9
Other Comprehensive Loss				(1.1)	(1.1)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	321.2	838.8	1,148.4	1.9	2,310.3
Common Stock Dividends			(337.5)		(337.5)
ASU 2018-02 Adoption				0.4	0.4
Net Income			325.5		325.5
Other Comprehensive Loss				(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	321.2	838.8	1,136.4	1.0	2,297.4
Common Stock Dividends			(85.0)		(85.0)
Net Income			297.1		297.1
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 321.2	$ 838.8	$ 1,348.5	$ —	$ 2,508.5

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.7	$ 4.9
Restricted Cash for Securitized Funding	—	27.6
Accounts Receivable:		
Customers	53.0	111.1
Affiliated Companies	59.3	70.8
Accrued Unbilled Revenues	20.3	21.4
Miscellaneous	0.5	0.3
Allowance for Uncollectible Accounts	(0.7)	(1.0)
Total Accounts Receivable	132.4	202.6
Materials and Supplies	52.3	42.9
Renewable Energy Credits	30.9	25.9
Prepayments and Other Current Assets	19.2	15.7
TOTAL CURRENT ASSETS	238.5	319.6
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,686.3	2,544.3
Distribution	5,323.5	4,942.3
Other Property, Plant and Equipment	765.8	574.8
Construction Work in Progress	394.4	432.1
Total Property, Plant and Equipment	9,170.0	8,493.5
Accumulated Depreciation and Amortization	2,263.0	2,218.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,907.0	6,274.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	351.8	387.5
Securitized Assets	—	12.9
Deferred Charges and Other Noncurrent Assets	546.3	441.0
TOTAL OTHER NONCURRENT ASSETS	898.1	841.4
TOTAL ASSETS	$ 8,043.6	$ 7,435.9

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	**2018**
CURRENT LIABILITIES		
Advances from Affiliates	$ 131.0	$ 114.1
Accounts Payable:		
General	233.7	211.9
Affiliated Companies	103.6	102.9
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2019 and 2018 Amounts Include $0 and $47.8, Respectively, Related to Ohio Phase-in-Recovery Funding)	0.1	47.9
Risk Management Liabilities	7.3	5.8
Customer Deposits	70.6	113.1
Accrued Taxes	587.9	537.8
Obligations Under Operating Leases	12.5	—
Other Current Liabilities	151.2	214.2
TOTAL CURRENT LIABILITIES	1,297.9	1,347.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,081.9	1,668.7
Long-term Risk Management Liabilities	96.3	93.8
Deferred Income Taxes	849.4	763.3
Regulatory Liabilities and Deferred Investment Tax Credits	1,090.9	1,221.2
Obligations Under Operating Leases	76.0	—
Deferred Credits and Other Noncurrent Liabilities	42.7	43.8
TOTAL NONCURRENT LIABILITIES	4,237.2	3,790.8
TOTAL LIABILITIES	5,535.1	5,138.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
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	1,348.5	1,136.4
Accumulated Other Comprehensive Income (Loss)	—	1.0
TOTAL COMMON SHAREHOLDER'S EQUITY	2,508.5	2,297.4
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 8,043.6	$ 7,435.9

See Notes to Financial Statements of Registrants beginning on page 156.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 297.1	$ 325.5	$ 323.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	240.9	259.7	225.9
Amortization of Generation Deferrals	65.3	223.9	229.2
Deferred Income Taxes	43.8	(36.2)	147.9
Allowance for Equity Funds Used During Construction	(18.2)	(9.8)	(6.4)
Mark-to-Market of Risk Management Contracts	4.0	(32.2)	13.0
Pension Contributions to Qualified Plan Trust	—	—	(8.2)
Property Taxes	(33.7)	(12.5)	(17.9)
Refund of Global Settlement	(16.5)	(5.5)	(98.2)
Reversal of Regulatory Provision	(56.2)	—	—
Change in Regulatory Assets	(20.1)	171.5	(70.7)
Change in Other Noncurrent Assets	(35.3)	(11.5)	(54.7)
Change in Other Noncurrent Liabilities	(93.2)	53.8	15.8
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	75.0	43.1	(30.1)
Materials and Supplies	(16.4)	(11.3)	(11.1)
Accounts Payable	0.4	(13.8)	11.6
Accrued Taxes, Net	38.7	26.8	(9.4)
Other Current Assets	0.8	8.1	(9.2)
Other Current Liabilities	(55.2)	49.1	(29.2)
Net Cash Flows from Operating Activities	421.2	1,028.7	622.2
INVESTING ACTIVITIES			
Construction Expenditures	(799.2)	(725.9)	(567.7)
Change in Advances to Affiliates, Net	—	—	24.2
Other Investing Activities	55.1	18.4	12.6
Net Cash Flows Used for Investing Activities	(744.1)	(707.5)	(530.9)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	444.3	392.8	—
Change in Advances from Affiliates, Net	16.9	26.3	87.8
Retirement of Long-term Debt – Nonaffiliated	(80.3)	(397.1)	(46.4)
Principal Payments for Finance Lease Obligations	(3.5)	(3.8)	(4.1)
Dividends Paid on Common Stock	(85.0)	(337.5)	(130.0)
Other Financing Activities	1.7	0.9	0.8
Net Cash Flows from (Used for) Financing Activities	294.1	(318.4)	(91.9)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(28.8)	2.8	(0.6)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	32.5	29.7	30.3
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 3.7	$ 32.5	$ 29.7
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 100.6	$ 97.1	$ 100.0
Net Cash Paid for Income Taxes	7.3	51.3	48.5
Noncash Acquisitions Under Finance Leases	11.3	4.4	4.5
Construction Expenditures Included in Current Liabilities as of December 31,	125.9	98.2	87.8

See Notes to Financial Statements of Registrants beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, PSO engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 559,000 retail customers in its service territory in eastern and southwestern Oklahoma. PSO sells electric power at wholesale to other utilities, municipalities and electric cooperatives. PSO shares off-system sales margins with its customers.

AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on PSO's behalf. PSO shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with SWEPCo. Power and natural gas risk management activities are allocated based on the Operating Agreement. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

PSO is jointly and severally liable for activity conducted by AEPSC on the behalf of PSO and SWEPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in millions of KWhs)		
Retail:			
Residential	6,273	6,452	5,943
Commercial	4,958	5,005	4,959
Industrial	6,156	6,120	5,882
Miscellaneous	1,246	1,263	1,242
Total Retail (a)	18,633	18,840	18,026
Wholesale	714	758	355
Total KWhs	19,347	19,598	18,381

(a) 2018 and 2017 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

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in degree days)		
Actual – Heating (a)	1,846	1,886	1,249
Normal – Heating (b)	1,751	1,752	1,776
Actual – Cooling (c)	2,265	2,445	2,131
Normal – Cooling (b)	2,160	2,149	2,147

(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.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$	83.2
Changes in Gross Margin:		
Retail Margins (a)		9.1
Margins from Off-system Sales		0.7
Transmission Revenues		(11.2)
Other Revenues		2.3
Total Change in Gross Margin		0.9
Changes in Expenses and Other:		
Other Operation and Maintenance		61.9
Depreciation and Amortization		(5.5)
Taxes Other Than Income Taxes		(0.5)
Interest Income		1.1
Allowance for Funds Used During Construction		2.3
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(3.0)
Total Change in Expenses and Other		56.0
Income Tax Expense		(2.5)
Year Ended December 31, 2019	$	137.6

(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 $9 million primarily due to the following:
  - A $46 million increase due to new base rates implemented in April 2019 and March 2018.
  - A $4 million increase in revenue from rate riders. This increase was partially offset in other expense items below.

These increases were partially offset by:
  - A $17 million decrease in weather-normalized margins.
  - A $13 million decrease in weather-related usage due to a 7% decrease in cooling degree days.
  - A $9 million decrease due to the impact of Tax Reform. This decrease was partially offset in Income Tax Expense below.
- **Transmission Revenues** decreased $11 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 $62 million primarily due to the following:
  - A $34 million decrease in transmission expenses primarily due to decreased SPP transmission services.
  - A $22 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.

These decreases were partially offset by:
  - A $3 million increase due to a charitable contribution to the AEP Foundation.

- **Depreciation and Amortization** expenses increased $6 million primarily due to higher depreciable base and new rates implemented in March 2018.
- **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 Retail Margins above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Public Service Company of Oklahoma

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Public Service Company of Oklahoma (the "Company") as of December 31, 2019 and 2018, and the related statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Public Service Company of Oklahoma (PSO) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. PSO's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of PSO's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded PSO's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, PSO's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit PSO to provide only management's report in this annual report.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,469.6	$ 1,537.6	$ 1,417.5
Sales to AEP Affiliates	6.1	5.4	4.3
Other Revenues	6.1	4.3	5.4
TOTAL REVENUES	1,481.8	1,547.3	1,427.2
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	195.1	240.5	134.5
Purchased Electricity for Resale	458.9	479.9	514.9
Other Operation	315.0	372.8	315.1
Maintenance	100.7	104.8	120.3
Depreciation and Amortization	169.5	164.0	130.4
Taxes Other Than Income Taxes	43.3	42.8	40.5
TOTAL EXPENSES	1,282.5	1,404.8	1,255.7
OPERATING INCOME	199.3	142.5	171.5
Other Income (Expense):			
Interest Income	1.2	0.1	0.1
Allowance for Equity Funds Used During Construction	2.7	0.4	0.5
Non-Service Cost Components of Net Periodic Benefit Cost	8.4	8.7	3.4
Interest Expense	(66.5)	(63.5)	(53.4)
INCOME BEFORE INCOME TAX EXPENSE	145.1	88.2	122.1
Income Tax Expense	7.5	5.0	50.1
NET INCOME	$ 137.6	$ 83.2	$ 72.0

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

See Notes to Financial Statements of Registrants beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
Net Income	$ 137.6	$ 83.2	$ 72.0
OTHER COMPREHENSIVE LOSS, NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(0.3), $(0.3) and $(0.4) in 2019, 2018 and 2017, Respectively	(1.0)	(1.0)	(0.8)
TOTAL COMPREHENSIVE INCOME	$ 136.6	$ 82.2	$ 71.2

*See Notes to Financial Statements of Registrants beginning on page 156***.**

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 157.2	$ 364.0	$ 689.5	$ 3.4	$ 1,214.1
Common Stock Dividends			(70.0)		(70.0)
Net Income			72.0		72.0
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	157.2	364.0	691.5	2.6	1,215.3
Common Stock Dividends			(50.0)		(50.0)
ASU 2018-02 Adoption				0.5	0.5
Net Income			83.2		83.2
Other Comprehensive Loss				(1.0)	(1.0)
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			137.6		137.6
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 157.2	$ 364.0	$ 851.0	$ 1.1	$ 1,373.3

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1.5	$ 2.0
Advances to Affiliates	38.8	—
Accounts Receivable:		
Customers	28.9	32.5
Affiliated Companies	20.6	26.2
Miscellaneous	0.6	5.7
Allowance for Uncollectible Accounts	(0.3)	(0.1)
Total Accounts Receivable	49.8	64.3
Fuel	12.2	12.3
Materials and Supplies	46.8	44.8
Risk Management Assets	15.8	10.4
Accrued Tax Benefits	11.3	14.7
Prepayments and Other Current Assets	12.0	9.4
TOTAL CURRENT ASSETS	188.2	157.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,574.6	1,577.0
Transmission	948.5	892.3
Distribution	2,684.8	2,572.8
Other Property, Plant and Equipment	342.1	303.5
Construction Work in Progress	133.4	94.0
Total Property, Plant and Equipment	5,683.4	5,439.6
Accumulated Depreciation and Amortization	1,580.1	1,472.9
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,103.3	3,966.7
OTHER NONCURRENT ASSETS		
Regulatory Assets	375.2	369.0
Employee Benefits and Pension Assets	43.9	31.7
Operating Lease Assets	36.8	—
Deferred Charges and Other Noncurrent Assets	4.1	7.1
TOTAL OTHER NONCURRENT ASSETS	460.0	407.8
TOTAL ASSETS	$ 4,751.5	$ 4,532.4

See Notes to Financial Statements of Registrants beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2019 and 2018

	December 31,	
	2019	2018
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 105.5
Accounts Payable:		
General	134.3	126.9
Affiliated Companies	59.3	47.1
Long-term Debt Due Within One Year – Nonaffiliated	13.2	375.5
Risk Management Liabilities	—	1.0
Customer Deposits	58.9	58.6
Accrued Taxes	22.9	22.4
Obligations Under Operating Leases	5.8	—
Regulatory Liability for Over-Recovered Fuel Costs	63.9	20.1
Other Current Liabilities	87.5	64.5
TOTAL CURRENT LIABILITIES	445.8	821.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,373.0	911.5
Deferred Income Taxes	628.3	607.8
Regulatory Liabilities and Deferred Investment Tax Credits	837.2	864.7
Asset Retirement Obligations	44.5	46.3
Obligations Under Operating Leases	31.0	—
Deferred Credits and Other Noncurrent Liabilities	18.4	32.5
TOTAL NONCURRENT LIABILITIES	2,932.4	2,462.8
TOTAL LIABILITIES	3,378.2	3,284.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
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	851.0	724.7
Accumulated Other Comprehensive Income (Loss)	1.1	2.1
TOTAL COMMON SHAREHOLDER'S EQUITY	1,373.3	1,248.0
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 4,751.5	$ 4,532.4

See Notes to Financial Statements of Registrants beginning on page 156.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 137.6	$ 83.2	$ 72.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	169.5	164.0	130.4
Deferred Income Taxes	(18.2)	(31.1)	124.7
Allowance for Equity Funds Used During Construction	(2.7)	(0.4)	(0.5)
Mark-to-Market of Risk Management Contracts	(6.4)	(3.0)	(5.6)
Pension Contributions to Qualified Plan Trust	—	—	(5.3)
Deferred Fuel Over/Under-Recovery, Net	43.8	57.4	(5.4)
Provision for Refund, Net	(9.1)	3.8	(43.5)
Change in Other Noncurrent Assets	5.7	—	(27.2)
Change in Other Noncurrent Liabilities	1.8	17.6	4.5
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	15.4	5.1	(10.9)
Fuel, Materials and Supplies	(1.9)	(2.6)	13.0
Accounts Payable	7.0	17.7	(10.7)
Accrued Taxes, Net	3.9	13.2	0.8
Other Current Assets	(0.7)	(0.8)	(2.1)
Other Current Liabilities	4.6	6.4	3.9
Net Cash Flows from Operating Activities	350.3	330.5	238.1
INVESTING ACTIVITIES			
Construction Expenditures	(291.9)	(240.2)	(266.1)
Change in Advances to Affiliates, Net	(38.8)	—	—
Other Investing Activities	2.6	7.2	4.6
Net Cash Flows Used for Investing Activities	(328.1)	(233.0)	(261.5)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	349.5	—	—
Change in Advances from Affiliates, Net	(105.5)	(44.1)	97.6
Retirement of Long-term Debt – Nonaffiliated	(250.5)	(0.5)	(0.5)
Make Whole Premium on Extinguishment of Long-term Debt	(3.0)	—	—
Principal Payments for Finance Lease Obligations	(3.1)	(3.3)	(3.9)
Dividends Paid on Common Stock	(11.3)	(50.0)	(70.0)
Other Financing Activities	1.2	0.8	0.3
Net Cash Flows from (Used for) Financing Activities	(22.7)	(97.1)	23.5
Net Increase (Decrease) in Cash and Cash Equivalents	(0.5)	0.4	0.1
Cash and Cash Equivalents at Beginning of Period	2.0	1.6	1.5
Cash and Cash Equivalents at End of Period	$ 1.5	$ 2.0	$ 1.6
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 61.1	$ 62.0	$ 61.5
Net Cash Paid (Received) for Income Taxes	22.4	17.9	(72.6)
Noncash Acquisitions Under Finance Leases	5.3	4.3	2.1
Construction Expenditures Included in Current Liabilities as of December 31,	46.0	33.2	23.1

See Notes to Financial Statements of Registrants beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, SWEPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 540,000 retail customers in its service territory in northeastern and the panhandle of Texas, northwestern Louisiana and western Arkansas. SWEPCo consolidates its wholly-owned subsidiary, Southwest Arkansas Utilities Corporation. SWEPCo also consolidates Sabine Mining Company, a variable interest entity. SWEPCo sells electric power at wholesale to other utilities, municipalities and electric cooperatives. SWEPCo shares off-system sales margins with its customers.

AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on SWEPCo's behalf. SWEPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with PSO. Power and natural gas risk management activities are allocated based on the Operating Agreement. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

SWEPCo is jointly and severally liable for activity conducted by AEPSC on the behalf of PSO and SWEPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in millions of KWhs)		
Retail:			
Residential	6,303	6,564	5,903
Commercial	5,776	5,911	5,824
Industrial	5,337	5,391	5,339
Miscellaneous	80	79	81
Total Retail (a)	17,496	17,945	17,147
Wholesale	6,791	7,071	8,324
Total KWhs	24,287	25,016	25,471

(a) 2018 and 2017 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

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in degree days)		
Actual – Heating (a)	1,174	1,308	829
Normal – Heating (b)	1,191	1,195	1,208
Actual – Cooling (c)	2,392	2,560	2,197
Normal – Cooling (b)	2,321	2,311	2,312

(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.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Year Ended December 31, 2018	$	147.2
Changes in Gross Margin:		
Retail Margins (a)		(6.0)
Margins from Off-system Sales		(1.9)
Transmission Revenues		(35.4)
Other Revenues		(0.6)
Total Change in Gross Margin		(43.9)
Changes in Expenses and Other:		
Other Operation and Maintenance		32.1
Depreciation and Amortization		(9.6)
Taxes Other Than Income Taxes		(0.6)
Interest Income		(2.8)
Allowance for Equity Funds Used During Construction		0.8
Non-Service Cost Components of Net Periodic Benefit Cost		(0.2)
Interest Expense		8.8
Total Change in Expenses and Other		28.5
Income Tax Expense (Benefit)		25.1
Equity Earnings (Loss) of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interest		1.4
Year Ended December 31, 2019	$	158.6

(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 $6 million primarily due to the following:
  - A $19 million decrease in weather-related usage primarily due to a 7% decrease in cooling degree days and a 10% decrease in heating degree days.
  - A $12 million decrease due to the impact of Tax Reform. This decrease was partially offset in Income Tax Expense (Benefit) below.

  These decreases were partially offset by:
  - A $20 million increase primarily due to rider and base rate revenue increases in Louisiana and Texas. This increase was partially offset in other expense items below.
  - A $6 million increase in weather-normalized margins.
- **Transmission Revenues** decreased $35 million primarily due to the following:
  - A $40 million decrease in the annual SPP formula rate true-up.
  - An $8 million decrease primarily due to a reduction in SPP Base Plan Funding revenues.

  These decreases were partially offset by:
  - A $13 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 $32 million primarily due to the following:
  - A $28 million decrease due to Wind Catcher Project expenses incurred in 2018.
  - A $20 million decrease in affiliated SPP transmission expenses primarily due to the annual formula rate true-up.

  These decreases were partially offset by:
  - An $11 million increase in storm-related expenses.
  - A $6 million increase due to a charitable contribution to the AEP Foundation.
- **Depreciation and Amortization** expenses increased $10 million primarily due to higher depreciation rates implemented in the third quarter of 2018 and a higher depreciable base.
- **Interest Expense** decreased $9 million primarily due to lower interest rates on outstanding long-term debt.
- **Income Tax Expense (Benefit)** decreased $25 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements and a decrease in state tax expense. This decrease was partially offset in Retail Margins above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Southwestern Electric Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management assessed the effectiveness of SWEPCo's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded SWEPCo's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, SWEPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit SWEPCo to provide only management's report in this annual report.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,744.6	$ 1,791.9	$ 1,752.1
Sales to AEP Affiliates	36.9	35.1	25.9
Provision for Refund - Affiliated	(32.0)	(6.7)	—
Other Revenues	1.4	1.6	1.9
TOTAL REVENUES	1,750.9	1,821.9	1,779.9
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	472.8	502.3	496.1
Purchased Electricity for Resale	179.5	177.1	168.7
Other Operation	348.0	384.2	318.3
Maintenance	145.6	141.5	143.5
Asset Impairments and Other Related Charges	—	—	33.6
Depreciation and Amortization	249.1	239.5	217.4
Taxes Other Than Income Taxes	100.2	99.6	98.3
TOTAL EXPENSES	1,495.2	1,544.2	1,475.9
OPERATING INCOME	255.7	277.7	304.0
Other Income (Expense):			
Interest Income	2.6	5.4	2.7
Allowance for Equity Funds Used During Construction	6.8	6.0	2.4
Non-Service Cost Component of Net Periodic Benefit Cost	8.5	8.7	3.7
Interest Expense	(119.1)	(127.9)	(123.4)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS (LOSS)	154.5	169.9	189.4
Income Tax Expense (Benefit)	(4.7)	20.4	48.1
Equity Earnings (Loss) of Unconsolidated Subsidiary	3.0	2.7	(3.8)
NET INCOME	162.2	152.2	137.5
Net Income Attributable to Noncontrolling Interest	3.6	5.0	12.8
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 158.6	$ 147.2	$ 124.7

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

See Notes to Financial Statements of Registrants beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
Net Income	$ 162.2	$ 152.2	$ 137.5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0.4, $1.1 and $0.8 in 2019, 2018 and 2017, Respectively	1.5	4.0	1.4
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.3), $(0.4) and $(0.4) in 2019, 2018 and 2017, Respectively	(1.1)	(1.4)	(0.7)
Pension and OPEB Funded Status, Net of Tax of $1, $(0.8) and $2.5 in 2019, 2018 and 2017, Respectively	3.7	(3.1)	4.7
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	4.1	(0.5)	5.4
TOTAL COMPREHENSIVE INCOME	166.3	151.7	142.9
Total Comprehensive Income Attributable to Noncontrolling Interest	3.6	5.0	12.8
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 162.7	$ 146.7	$ 130.1

See Notes to Financial Statements of Registrants beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2016	$ 135.7	$ 676.6	$ 1,411.9	$ (9.4)	$ 0.4	$ 2,215.2
Common Stock Dividends			(110.0)			(110.0)
Common Stock Dividends – Nonaffiliated					(13.6)	(13.6)
Net Income			124.7		12.8	137.5
Other Comprehensive Income				5.4		5.4
TOTAL EQUITY – DECEMBER 31, 2017	135.7	676.6	1,426.6	(4.0)	(0.4)	2,234.5
Common Stock Dividends			(65.0)			(65.0)
Common Stock Dividends – Nonaffiliated					(4.3)	(4.3)
ASU 2018-02 Adoption			(0.4)	(0.9)		(1.3)
Net Income			147.2		5.0	152.2
Other Comprehensive Loss				(0.5)		(0.5)
TOTAL EQUITY – DECEMBER 31, 2018	135.7	676.6	1,508.4	(5.4)	0.3	2,315.6
Common Stock Dividends			(37.5)			(37.5)
Common Stock Dividends – Nonaffiliated					(3.3)	(3.3)
Net Income			158.6		3.6	162.2
Other Comprehensive Income				4.1		4.1
TOTAL EQUITY – DECEMBER 31, 2019	$ 135.7	$ 676.6	$ 1,629.5	$ (1.3)	$ 0.6	$ 2,441.1

See Notes to Financial Statements of Registrants beginning on page 156.

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

	December 31,	
	2019	2018
CURRENT ASSETS		
Cash and Cash Equivalents (December 31, 2019 and 2018 Amounts Include $0 and $22, Respectively, Related to Sabine)	$ 1.6	$ 24.5
Advances to Affiliates	2.1	83.4
Accounts Receivable:		
Customers	29.0	24.5
Affiliated Companies	34.5	28.8
Miscellaneous	13.5	20.2
Allowance for Uncollectible Accounts	(1.7)	(0.7)
Total Accounts Receivable	75.3	72.8
Fuel (December 31, 2019 and 2018 Amounts Include $47 and $13.2, Respectively, Related to Sabine)	140.1	98.0
Materials and Supplies (December 31, 2019 and 2018 Amounts Include $23.1 and $22.5, Respectively, Related to Sabine)	94.0	90.0
Risk Management Assets	6.4	4.8
Regulatory Asset for Under-Recovered Fuel Costs	4.9	18.8
Prepayments and Other Current Assets	29.7	22.2
TOTAL CURRENT ASSETS	354.1	414.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,691.4	4,672.6
Transmission	2,056.5	1,866.9
Distribution	2,270.7	2,178.6
Other Property, Plant and Equipment (December 31, 2019 and 2018 Amounts Include $212.3 and $276.9, Respectively, Related to Sabine)	733.4	762.7
Construction Work in Progress	216.9	199.3
Total Property, Plant and Equipment	9,968.9	9,680.1
Accumulated Depreciation and Amortization (December 31, 2019 and 2018 Amounts Include $107.5 and $174.6, Respectively, Related to Sabine)	2,873.7	2,808.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,095.2	6,871.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	222.4	230.8
Deferred Charges and Other Noncurrent Assets	160.5	111.2
TOTAL OTHER NONCURRENT ASSETS	382.9	342.0
TOTAL ASSETS	$ 7,832.2	$ 7,628.3

See Notes to Financial Statements of Registrants beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2019 and 2018

	December 31,	
	2019	**2018**
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 59.9	$ —
Accounts Payable:		
General	138.0	129.1
Affiliated Companies	53.6	64.2
Short-term Debt – Nonaffiliated	18.3	—
Long-term Debt Due Within One Year – Nonaffiliated	121.2	59.7
Risk Management Liabilities	1.9	0.4
Customer Deposits	65.0	64.5
Accrued Taxes	41.8	42.8
Accrued Interest	34.6	34.7
Obligations Under Operating Leases	6.5	—
Other Current Liabilities	133.9	117.5
TOTAL CURRENT LIABILITIES	674.7	512.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,534.4	2,653.7
Long-term Risk Management Liabilities	3.1	2.2
Deferred Income Taxes	940.9	902.8
Regulatory Liabilities and Deferred Investment Tax Credits	892.3	923.0
Asset Retirement Obligations	196.7	191.3
Employee Benefits and Pension Obligations	28.1	24.8
Obligations Under Operating Leases	34.7	—
Deferred Credits and Other Noncurrent Liabilities	86.2	102.0
TOTAL NONCURRENT LIABILITIES	4,716.4	4,799.8
TOTAL LIABILITIES	5,391.1	5,312.7
Rate Matters (Notes 4)		
Commitments and Contingencies (Note 6)		
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	1,629.5	1,508.4
Accumulated Other Comprehensive Income (Loss)	(1.3)	(5.4)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,440.5	2,315.3
Noncontrolling Interest	0.6	0.3
TOTAL EQUITY	2,441.1	2,315.6
TOTAL LIABILITIES AND EQUITY	$ 7,832.2	$ 7,628.3

See Notes to Financial Statements of Registrants beginning on page 156.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 162.2	$ 152.2	$ 137.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	249.1	239.5	217.4
Deferred Income Taxes	(11.0)	1.2	80.5
Asset Impairments and Other Related Charges	—	—	33.6
Allowance for Equity Funds Used During Construction	(6.8)	(6.0)	(2.4)
Mark-to-Market of Risk Management Contracts	0.8	4.0	(5.6)
Pension Contributions to Qualified Plan Trust	—	—	(8.9)
Deferred Fuel Over/Under-Recovery, Net	16.5	(2.4)	(0.8)
Change in Other Noncurrent Assets	6.2	(18.8)	(9.2)
Change in Other Noncurrent Liabilities	2.7	42.8	4.7
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	—	53.5	(32.9)
Fuel, Materials and Supplies	(46.1)	3.5	(16.0)
Accounts Payable	(28.4)	0.9	10.5
Accrued Taxes, Net	(3.2)	2.3	45.7
Other Current Assets	(8.9)	15.6	5.2
Other Current Liabilities	6.7	16.5	(14.6)
Net Cash Flows from Operating Activities	339.8	504.8	444.7
INVESTING ACTIVITIES			
Construction Expenditures	(412.7)	(451.0)	(404.1)
Change in Advances to Affiliates, Net	81.3	(81.4)	167.8
Proceeds from Sales of Assets	0.2	1.4	12.6
Other Investing Activities	1.0	2.1	3.1
Net Cash Flows Used for Investing Activities	(330.2)	(528.9)	(220.6)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	—	1,065.7	114.6
Change in Short-term Debt – Nonaffiliated	18.3	(22.0)	22.0
Change in Advances from Affiliates, Net	59.9	(118.7)	118.7
Retirement of Long-term Debt – Nonaffiliated	(59.7)	(794.5)	(353.7)
Principal Payments for Finance Lease Obligations	(11.0)	(11.5)	(11.3)
Dividends Paid on Common Stock	(37.5)	(65.0)	(110.0)
Dividends Paid on Common Stock – Nonaffiliated	(3.3)	(4.3)	(13.6)
Other Financing Activities	0.8	(2.7)	0.5
Net Cash Flows from (Used for) Financing Activities	(32.5)	47.0	(232.8)
Net Increase (Decrease) in Cash and Cash Equivalents	(22.9)	22.9	(8.7)
Cash and Cash Equivalents at Beginning of Period	24.5	1.6	10.3
Cash and Cash Equivalents at End of Period	$ 1.6	$ 24.5	$ 1.6
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 111.1	$ 125.7	$ 124.4
Net Cash Paid (Received) for Income Taxes	8.6	18.8	(75.3)
Noncash Acquisitions Under Finance Leases	7.4	3.6	3.3
Construction Expenditures Included in Current Liabilities as of December 31,	69.1	42.0	71.2

See Notes to Financial Statements of Registrants beginning on page 156.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

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

1. <u>ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES</u>

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

ORGANIZATION

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

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

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP's public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in the eleven state operating territories in which they operate. The FERC also regulates the Registrants' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

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

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrants' retail public utility subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. For generation in Ohio, customers who have not switched to a CRES provider for generation pay market-based auction rates. In addition, all OPCo distribution customers paid for certain legacy generation deferral balances that were fully recovered as of December 31, 2019 and continue to pay for certain legacy deferred generation-related costs through PUCO approved riders. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing is conducted by REPs. AEP has no active REPs in ERCOT. AEP's nonregulated subsidiaries enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT.

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

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

In addition, the FERC regulates the SIA, Operating Agreement, Transmission Agreement and Transmission Coordination Agreement, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA. See Note 16 - Related Party Transactions for additional information.

Principles of Consolidation

AEP's consolidated financial statements include its wholly-owned and majority-owned subsidiaries and VIEs of which AEP is the primary beneficiary. The consolidated financial statements for AEP Texas include the Registrant Subsidiary, its wholly-owned subsidiaries, Transition Funding (consolidated VIEs) and Restoration Funding (a consolidated VIE). The consolidated financial statements for APCo include the Registrant Subsidiary, its wholly-owned subsidiaries and Appalachian Consumer Rate Relief Funding (a consolidated VIE). The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (consolidated VIEs). The consolidated financial statements for OPCo include the Registrant Subsidiary and Ohio Phase-in-Recovery Funding (a consolidated VIE). In July 2019, the Ohio Phase-in Recovery Funding securitization bonds matured. The consolidated financial statements for SWEPCo include the Registrant Subsidiary, its wholly-owned subsidiary and Sabine (a consolidated VIE). Intercompany items are eliminated in consolidation.

The equity method of accounting is used for equity investments where the Registrants exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income.

AEP, AEP Texas, I&M, PSO and SWEPCo have ownership interests in generating units that are jointly-owned. The proportionate share of the operating costs associated with such facilities is included on the income statements and the assets and liabilities are reflected on the balance sheets. See Note 17 - Variable Interest Entities and Equity Method Investments and Note 18 - Property, Plant and Equipment for additional information.

Accounting for the Effects of Cost-Based Regulation

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

Use of Estimates

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

Cash and Cash Equivalents

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

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

Restricted Cash primarily includes funds held by trustees for the payment of securitization bonds and contractually restricted deposits held for the future payment of the remaining construction activities at the Santa Rita East wind generation facility.

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 statement of cash flows:

	December 31, 2019			
	AEP	AEP Texas	APCo	OPCo
	(in millions)			
Cash and Cash Equivalents	$ 246.8	$ 3.1	$ 3.3	$ 3.7
Restricted Cash	185.8	154.7	23.5	—
Total Cash, Cash Equivalents and Restricted Cash	$ 432.6	$ 157.8	$ 26.8	$ 3.7

	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

Other Temporary Investments (Applies to AEP)

Other Temporary Investments primarily include marketable securities and investments by its protected cell of EIS. These securities have readily determinable fair values and are carried at fair value with changes in fair value recognized in net income. The cost of securities sold is based on the specific identification or weighted-average cost method. See "Fair Value Measurements of Other Temporary Investments" section of Note 11 for additional information.

Inventory

Fossil fuel inventories are carried at average cost with the exception of AGR and AEP's non-regulated ownership share of Oklaunion Power Station, which is carried at the lower of average cost or net realizable value. Materials and supplies inventories are carried at average cost. AEP and SWEPCo reclassified approximately $23 million, as of December 31, 2018, from Fuel to Materials and Supplies related to Sabine.

Accounts Receivable

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

Revenue is recognized over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, the Registrants accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

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

Allowance for Uncollectible Accounts

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

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

APCo, I&M, OPCo, PSO and SWEPCo do not have any significant customers that comprise 10% or more of their operating revenues. AEP Texas had significant transactions with REPs which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable – Customers as of December 31:

Significant Customers of AEP Texas: Centrica, TXU Energy and Reliant Energy	**2019**	**2018**	**2017 (a)**
Percentage of Total Revenues	48%	45%	35%
Percentage of Accounts Receivable – Customers	43%	35%	31%

(a) TXU Energy did not meet the Total Revenue threshold of 10% in order to be considered a significant customer.

AEPTCo had significant transactions with AEP Subsidiaries which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Total Accounts Receivable as of December 31:

Significant Customers of AEPTCo: AEP Subsidiaries	**2019**	**2018**	**2017**
Percentage of Total Revenues	79%	77%	80%
Percentage of Total Accounts Receivable	78%	84%	85%

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

Renewable Energy Credits (Applies to all Registrants except AEP Texas and AEPTCo)

In regulated jurisdictions, the Registrants record renewable energy credits (RECs) at cost. For AEP's competitive generation business, management records RECs at the lower of cost or market. The Registrants follow the inventory model for these RECs. RECs expected to be consumed within one year are reported in Materials and Supplies on the balance sheets. RECs with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs are consumed to meet applicable state renewable portfolio standards and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment

Regulated

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

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

Nuclear fuel, including nuclear fuel in the fabrication phase, is included in Other Property, Plant and Equipment on the balance sheets.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in-service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

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

Allowance for Funds Used During Construction and Interest Capitalization

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

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities (Applies to all Registrants except AEPTCo)

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 benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

Assets in the benefits and nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and 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. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs (Applies to all Registrants except AEP Texas and AEPTCo)

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

Changes in fuel costs, including purchased power in Kentucky for KPCo, Indiana and Michigan for I&M, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO, in Virginia and West Virginia for APCo and in West Virginia for WPCo are reflected in rates in a timely manner generally through the FAC. In Ohio, purchased power is reflected in rates through various PUCO approved mechanisms. The FAC generally includes some sharing of off-system sales margins. In West Virginia for APCo and WPCo, all of the non-merchant margins from off-system sales are given to customers through the FAC. A portion of margins from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan for I&M. Beginning in 2020, Arkansas for SWEPCo will start giving all margins from off-system sales to customers through the FAC. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

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

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

Retail and Wholesale Supply and Delivery of Electricity

The Registrants recognize revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrants recognize such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts. In accordance with the applicable state commission's regulatory treatment, PSO and SWEPCo do not include the fuel portion in unbilled revenue, but rather recognize such revenues when billed to customers.

Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations", and are recognized by the Registrants in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets. See Note 20 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

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

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

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

Energy Marketing and Risk Management Activities (Applies to all Registrants except AEPTCo)

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

The Registrants recognize revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

The Registrants use MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The Registrants include realized gains and losses on marketing and risk management transactions in revenues or expense based on the transaction's facts and circumstances. In certain jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

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

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

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over approximately 18 months, beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

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

Income Taxes and Investment and Production Tax Credits

The Registrants use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

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

AEP and subsidiaries apply the deferral methodology for the recognition of ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed into service, except where regulatory commissions reflect ITCs in the rate-making process, then amortization begins when the cash tax benefit is recognized. Alternatively, PTCs reduce income tax expense as they are earned. PTCs are earned when electricity is produced.

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

Excise Taxes (Applies to all Registrants except AEPTCo)

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

Debt

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

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

Goodwill (Applies to AEP)

When AEP acquires a business, as defined by the accounting guidance for "Business Combinations," management recognizes all acquired assets and liabilities at their fair value. To the extent that consideration exceeds the net fair value of the identified assets and liabilities, goodwill is recognized on the balance sheets. Goodwill is not amortized. Management tests acquired goodwill at the reporting unit level for impairment at least annually at its estimated fair value. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods.

Pension and OPEB Plans (Applies to all Registrants except AEPTCo)

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

Investments Held in Trust for Future Liabilities (Applies to all Registrants except AEPTCo)

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

Benefit Plans

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

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

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

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

Pension Plan Assets	Target
Equity	30%
Fixed Income	54%
Other Investments	15%
Cash and Cash Equivalents	1%

OPEB Plans Assets	Target
Equity	48%
Fixed Income	50%
Cash and Cash Equivalents	2%

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

For equity investments, the concentration limits are generally as follows:

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

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

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

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

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2019 and 2018, the fair value of securities on loan as part of the program was $246 million and $241 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2019 and 2018.

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

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

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

Nuclear decommissioning and 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 an external investment manager that 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. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss) (Applies to all Registrants except AEPTCo)

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

Stock-Based Compensation Plans

As of December 31, 2019, AEP had performance shares and restricted stock units outstanding under the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP). Upon vesting, all outstanding performance shares and restricted stock units settle in AEP common stock. Performance units awarded prior to 2017 and restricted stock units granted after January 1, 2013 and prior to January 1, 2017 that vested to executive officers were settled in cash. During 2019, all of the remaining performance units and restricted stock units that settle in cash were settled. The impact of AEP's stock-based compensation plans are insignificant to the financial statements of the Registrant Subsidiaries.

AEP maintains a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes AEP career shares maintained under the American Electric Power System Stock Ownership Requirement Plan (SORP), which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. AEP career shares are derived from vested performance shares granted to employees under the 2015 LTIP. AEP career shares accrue additional dividend shares in an amount equal to dividends paid on AEP common shares at the closing market price on the dividend payments date. All AEP career shares are settled in shares of AEP common stock after the executive's service with AEP ends.

Performance shares awarded after January 1, 2017 are classified as temporary equity in the Mezzanine Equity section of the balance sheets. These awards may be settled in cash upon an employee's qualifying termination due to a change in control. Because such event is not solely within the control of the company, these awards are classified outside of permanent equity.

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

Management measures and recognizes compensation expense for all share-based payment awards to employees and directors based on estimated fair values. For share-based payment awards with service only vesting conditions, management recognizes compensation expense on a straight-line basis. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2019, 2018 and 2017 is based on the number of outstanding awards at the end of each period without a reduction for estimated forfeitures. AEP accounts for forfeitures in the period in which they occur.

For the years ended December 31, 2019, 2018 and 2017, compensation cost is included in Net Income for the performance shares, career shares, restricted stock units and the non-employee director's stock units. Compensation cost may also be capitalized. See Note 15 - Stock-based Compensation for additional information.

Equity Investment in Unconsolidated Entities (Applies to AEP and SWEPCo)

The equity method of accounting is used for equity investments where either AEP or SWEPCo exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings (Loss) of Unconsolidated Subsidiaries on the statements of income. AEP and SWEPCo regularly monitor and evaluate 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.

AEP has various significant equity method investments, which include ETT, DHLC and five wind farms acquired in the purchase of Sempra Renewables LLC. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Years Ended December 31,					
	2019		2018		2017	
	(in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,921.1		$ 1,923.8		$ 1,912.6	
Weighted Average Number of Basic Shares Outstanding	493.7	$ 3.89	492.8	$ 3.90	491.8	$ 3.89
Weighted Average Dilutive Effect of Stock-Based Awards	1.6	(0.01)	1.0	—	0.8	(0.01)
Weighted Average Number of Diluted Shares Outstanding	495.3	$ 3.88	493.8	$ 3.90	492.6	$ 3.88

Equity Units issued in March 2019 are potentially dilutive securities but were excluded from the calculation of diluted EPS for the year ended December 31, 2019, as the dilutive stock price threshold was not met. See Note 14 - Financing Activities for additional information.

There were no antidilutive shares outstanding as of December 31, 2019, 2018 and 2017.

Reclassifications

Certain reclassifications have been made in the 2018 financial statements and notes to conform to the 2019 presentation.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2019, 2018 and 2017:

2019

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 2,203.7	$ 365.9	$ 176.0	$ 466.5	$ 330.6	$ 229.4	$ 162.5	$ 247.9
Amortization of Certain Securitized Assets	280.7	258.7	—	—	—	22.0	—	—
Amortization of Regulatory Assets and Liabilities	30.1	(2.3)	—	0.3	20.0	(10.5)	7.0	1.2
Total Depreciation and Amortization	$ 2,514.5	$ 622.3	$ 176.0	$ 466.8	$ 350.6	$ 240.9	$ 169.5	$ 249.1

2018

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,965.0	$ 262.2	$ 133.9	$ 428.1	$ 278.9	$ 232.6	$ 155.5	$ 237.0
Amortization of Certain Securitized Assets	287.9	240.0	—	—	—	47.9	—	—
Amortization of Regulatory Assets and Liabilities	33.7	(2.6)	—	0.3	14.2	(20.8)	8.5	2.5
Total Depreciation and Amortization	$ 2,286.6	$ 499.6	$ 133.9	$ 428.4	$ 293.1	$ 259.7	$ 164.0	$ 239.5

2017

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,709.1	$ 221.1	$ 95.7	$ 407.6	$ 203.1	$ 200.9	$ 131.4	$ 217.2
Amortization of Certain Securitized Assets	275.9	231.4	—	—	—	44.4	—	—
Amortization of Regulatory Assets and Liabilities	12.2	(2.4)	—	0.3	7.8	(19.4)	(1.0)	0.2
Total Depreciation and Amortization	$ 1,997.2	$ 450.1	$ 95.7	$ 407.9	$ 210.9	$ 225.9	$ 130.4	$ 217.4

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Years Ended December 31, 2019	2018	2017
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 1,022.5	$ 939.3	$ 858.3
Income Taxes	6.1	(24.7)	(1.1)
Noncash Investing and Financing Activities:			
Acquisitions Under Finance Leases	87.5	55.6	60.7
Construction Expenditures Included in Current Liabilities as of December 31,	1,341.1	1,120.4	1,330.8
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	—	—	71.8
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	0.1	4.0	—
Noncash Contribution of Assets by Noncontrolling Interest	—	84.0	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	0.3	2.2	2.6
Noncontrolling Interest Assumed with Sempra Renewables LLC and Santa Rita East Acquisition	253.4	—	—
Liabilities Assumed with Sempra Renewable LLC and Santa Rita East Acquisition	32.4	—	—

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 sheets 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 13 - 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. Entities are required to evaluate, and if necessary, recognize expected credit losses at the inception or initial acquisition of a financial instrument (or pool of financial instruments that share similar risk characteristics) subject to ASU 2016-13, and subsequently as of each reporting date. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

Management adopted ASU 2016-13 and its related implementation guidance effective January 1, 2020, by means of a cumulative-effect adjustment to the balance sheets. The adoption of the new standard did not have a material impact to financial position, and had no impact on the results of operations or cash flows. Additionally, the adoption of the new standard did not result in any changes to current accounting systems.

Implementation activities included: (1) the identification and evaluation of the population of financial instruments within the AEP system that are subject to the new standard and, (2) the development of supporting valuation models to also contemplate appropriate metrics for current and supportable forecasted information. As required by ASU 2016-13, the financial instruments subject to the new standard were evaluated on a pool-basis to the extent such financial instruments shared similar risk characteristics.

Management continues to develop disclosures to comply with the requirements of ASU 2016-13 that are required in the first quarter of 2020. Management will continue to monitor for any potential industry implementation issues.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants except for AEPTCo. AEPTCo does not have any components of other comprehensive income for any period presented in the financial statements.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2019, 2018 and 2017. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 - Benefit Plans for additional details.

AEP

	Cash Flow Hedges		Pension and OPEB		
For the Year Ended December 31, 2019	**Commodity**	**Interest Rate**	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
			(in millions)		
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ 136.3	$ (221.1)	$ (120.4)
Change in Fair Value Recognized in AOCI	(127.2)	(0.2) (a)	—	57.7	(69.7)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (b)	(0.2)	—	—	—	(0.2)
Purchased Electricity for Resale (b)	59.5	—	—	—	59.5
Interest Expense (b)	—	1.5	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	(19.2)	—	(19.2)
Amortization of Actuarial (Gains) Losses	—	—	12.1	—	12.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	59.3	1.5	(7.1)	—	53.7
Income Tax (Expense) Benefit	12.6	0.2	(1.5)	—	11.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	46.7	1.3	(5.6)	—	42.4
Net Current Period Other Comprehensive Income (Loss)	(80.5)	1.1	(5.6)	57.7	(27.3)
Balance in AOCI as of December 31, 2019	$ (103.5)	$ (11.5)	$ 130.7	$ (163.4)	$ (147.7)

AEP

For the Year Ended December 31, 2018	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate	Securities Available for Sale	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
	(in millions)					
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)
Change in Fair Value Recognized in AOCI	37.3	2.3	—	—	(33.0)	6.6
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	(0.1)	—	—	—	—	(0.1)
Purchased Electricity for Resale (b)	(32.6)	—	—	—	—	(32.6)
Interest Expense (b)	—	1.1	—	—	—	1.1
Amortization of Prior Service Cost (Credit)	—	—	—	(19.5)	—	(19.5)
Amortization of Actuarial (Gains) Losses	—	—	—	12.8	—	12.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(32.7)	1.1	—	(6.7)	—	(38.3)
Income Tax (Expense) Benefit	(6.9)	0.3	—	(1.4)	—	(8.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(25.8)	0.8	—	(5.3)	—	(30.3)
Net Current Period Other Comprehensive Income (Loss)	11.5	3.1	—	(5.3)	(33.0)	(23.7)
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 December 31, 2018	$ (23.0)	$ (12.6)	$ —	$ 136.3	$ (221.1)	$ (120.4)

For the Year Ended December 31, 2017	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate	Securities Available for Sale	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
	(in millions)					
Balance in AOCI as of December 31, 2016	$ (23.1)	$ (15.7)	$ 8.4	$ 140.5	$ (266.4)	$ (156.3)
Change in Fair Value Recognized in AOCI	(20.4)	1.6	3.5	—	86.5	71.2
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	(5.6)	—	—	—	—	(5.6)
Purchased Electricity for Resale (b)	28.8	—	—	—	—	28.8
Interest Expense (b)	—	1.5	—	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	—	(19.6)	—	(19.6)
Amortization of Actuarial (Gains) Losses	—	—	—	21.3	—	21.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	23.2	1.5	—	1.7	—	26.4
Income Tax (Expense) Benefit	8.1	0.4	—	0.6	—	9.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	15.1	1.1	—	1.1	—	17.3
Net Current Period Other Comprehensive Income (Loss)	(5.3)	2.7	3.5	1.1	86.5	88.5
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)

AEP Texas

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.3	—	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.2	—	1.5
Income Tax (Expense) Benefit	0.3	—	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	1.1	2.3
Balance in AOCI as of December 31, 2019	$ (3.4)	$ 4.9	$ (14.3)	$ (12.8)

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)
Change in Fair Value Recognized in AOCI	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.3	—	1.6
Income Tax (Expense) Benefit	0.3	0.1	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	(1.0)	0.2
ASU 2018-02 Adoption	(0.9)	—	(1.8)	(2.7)
Balance in AOCI as of December 31, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (5.4)	$ 4.2	$ (13.7)	$ (14.9)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.4	—	1.7
Income Tax (Expense) Benefit	0.4	0.1	—	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.9	0.3	—	1.2
Net Current Period Other Comprehensive Income (Loss)	0.9	0.3	1.1	2.3
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)

APCo

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
	(in millions)			
Balance in AOCI as of December 31, 2018	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)
Change in Fair Value Recognized in AOCI	—	—	13.4	13.4
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.3)	—	(5.3)
Amortization of Actuarial (Gains) Losses	—	2.1	—	2.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(3.2)	—	(4.3)
Income Tax (Expense) Benefit	(0.2)	(0.7)	—	(0.9)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.9)	(2.5)	—	(3.4)
Net Current Period Other Comprehensive Income (Loss)	(0.9)	(2.5)	13.4	10.0
Balance in AOCI as of December 31, 2019	$ 0.9	$ 9.2	$ (5.1)	$ 5.0

For the Year Ended December 31, 2018	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
	(in millions)				
Balance in AOCI as of December 31, 2017	$ —	$ 2.2	$ 14.8	$ (15.7)	$ 1.3
Change in Fair Value Recognized in AOCI	(0.7)	—	—	(2.6)	(3.3)
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale (b)	0.9	—	—	—	0.9
Interest Expense (b)	—	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	—	1.3	—	1.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.9	(1.1)	(3.9)	—	(4.1)
Income Tax (Expense) Benefit	0.2	(0.2)	(0.8)	—	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.7	(0.9)	(3.1)	—	(3.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.9)	(3.1)	(2.6)	(6.6)
ASU 2018-02 Adoption	—	0.5	—	(0.2)	0.3
Balance in AOCI as of December 31, 2018	$ —	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
	(in millions)			
Balance in AOCI as of December 31, 2016	$ 2.9	$ 16.0	$ (27.3)	$ (8.4)
Change in Fair Value Recognized in AOCI	—	—	11.6	11.6
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	3.4	—	3.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(1.8)	—	(2.9)
Income Tax (Expense) Benefit	(0.4)	(0.6)	—	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.7)	(1.2)	—	(1.9)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.2)	11.6	9.7
Balance in AOCI as of December 31, 2017	$ 2.2	$ 14.8	$ (15.7)	$ 1.3

I&M

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)
Change in Fair Value Recognized in AOCI	—	—	0.8	0.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	(0.2)	—	1.8
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	(0.2)	—	1.4
Net Current Period Other Comprehensive Income (Loss)	1.6	(0.2)	0.8	2.2
Balance in AOCI as of December 31, 2019	$ (9.9)	$ 4.9	$ (6.6)	$ (11.6)

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)
Change in Fair Value Recognized in AOCI	—	—	(0.6)	(0.6)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	—	—	1.6
Net Current Period Other Comprehensive Income (Loss)	1.6	—	(0.6)	1.0
ASU 2018-02 Adoption	(2.4)	—	(0.3)	(2.7)
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)
Change in Fair Value Recognized in AOCI	—	—	2.8	2.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.9)	—	(0.9)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	2.8	4.1
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)

OPCo

For the Year Ended December 31, 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	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(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)
Balance in AOCI as of December 31, 2019	$ —

For the Year Ended December 31, 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 (b)	(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.7)
Income Tax (Expense) Benefit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.3)
Net Current Period Other Comprehensive Income (Loss)	(1.3)
ASU 2018-02 Adoption	0.4
Balance in AOCI as of December 31, 2018	$ 1.0

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.7)
Income Tax (Expense) Benefit	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.1)
Net Current Period Other Comprehensive Income (Loss)	(1.1)
Balance in AOCI as of December 31, 2017	$ 1.9

PSO

For the Year Ended December 31, 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	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(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)
Balance in AOCI as of December 31, 2019	$ 1.1

For the Year Ended December 31, 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 (b)	(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	0.5
Balance in AOCI as of December 31, 2018	$ 2.1

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.4
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of December 31, 2017	$ 2.6

SWEPCo

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
	(in millions)			
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (0.2)	$ (1.9)	$ (5.4)
Change in Fair Value Recognized in AOCI	—	—	3.7	3.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.9	—	—	1.9
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.9	(1.4)	—	0.5
Income Tax (Expense) Benefit	0.4	(0.3)	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.5	(1.1)	—	0.4
Net Current Period Other Comprehensive Income (Loss)	1.5	(1.1)	3.7	4.1
Balance in AOCI as of December 31, 2019	$ (1.8)	$ (1.3)	$ 1.8	$ (1.3)

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
	(in millions)			
Balance in AOCI as of December 31, 2017	$ (6.0)	$ 1.2	$ 0.8	$ (4.0)
Change in Fair Value Recognized in AOCI	2.3	—	(3.1)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.1	—	—	2.1
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.2	—	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.1	(1.8)	—	0.3
Income Tax (Expense) Benefit	0.4	(0.4)	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.7	(1.4)	—	0.3
Net Current Period Other Comprehensive Income (Loss)	4.0	(1.4)	(3.1)	(0.5)
ASU 2018-02 Adoption	(1.3)	—	0.4	(0.9)
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (0.2)	$ (1.9)	$ (5.4)

For the Year Ended December 31, 2017	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
	(in millions)			
Balance in AOCI as of December 31, 2016	$ (7.4)	$ 1.9	$ (3.9)	$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	4.7	4.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.2	—	—	2.2
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.2	(1.1)	—	1.1
Income Tax (Expense) Benefit	0.8	(0.4)	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.4	(0.7)	—	0.7
Net Current Period Other Comprehensive Income (Loss)	1.4	(0.7)	4.7	5.4
Balance in AOCI as of December 31, 2017	$ (6.0)	$ 1.2	$ 0.8	$ (4.0)

(a) The change in fair value includes $4 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the year ended December 31, 2019. See “Sempra Renewables LLC” section of Note 17 for additional information.
(b) Amounts reclassified to the referenced line item on the statements of income.

4. RATE MATTERS

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

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

Impact of Tax Reform

Rate and regulatory matters are impacted by federal income tax implications. In December 2017, Tax Reform was enacted, which impacts outstanding rate and regulatory matters. For additional details on the impact of Tax Reform, see Note 12 - Income Taxes.

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

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 normalization requirements. The rate case also seeks a prudence determination on all transmission and distribution capital additions through 2018 included in interim rates from 2008 to December 2019. As of December 31, 2019, AEP Texas' cumulative revenues from transmission and distribution interim rate increases are estimated to be approximately $1.4 billion and are subject to reconciliation in this base rate case.

In November 2019, ALJs issued a Proposal for Decision recommending a $60 million annual rate reduction based upon a 9.4% return on common equity. The ALJs also recommended disallowances that could potentially result in write-offs of $84 million related to capital incentives and $5 million related to other plant additions. Additionally, the ALJs recommended that AEP Texas should be required to file an application for a separate proceeding to determine if any refunds are required associated with any disallowances on distribution or transmission capital investments.

In February 2020, AEP Texas, the PUCT staff and various intervenors filed a stipulation and settlement agreement with the PUCT. The agreement includes a proposed annual base rate reduction of $40 million based upon a 9.4% return on common equity with a capital structure of 57.5% debt and 42.5% common equity. The agreement provides recovery of $26 million in capitalized vegetation management expenses that were incurred through 2018. The agreement includes disallowances of $23 million related to capital investments recorded through 2018 and $4 million related to rate case expenses. In addition, AEP Texas will refund: (a) $77 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to distribution customers over a one year period, (b) $31 million of Excess ADIT and excess federal income taxes collected as a result of Tax Reform to transmission customers as a one-time credit and (c) $30 million of previously collected rates that were subject to reconciliation in this proceeding over a one year period with no carrying costs. Per the agreement, AEP Texas is required to file its next base rate case within four years of the date of the final order. The agreement also: (a) states future financially based capital incentives will not be included in interim transmission and distribution rates, (b) contains various ring-fencing provisions and (c) will allow the PUCT to decide whether to adopt a dividend restriction ring-fencing provision.

As a result of the stipulation and settlement agreement, AEP Texas (a) recorded an impairment of $33 million in December 2019 related to capital investments, which included $10 million of current year investments, in Asset Impairments and Other Related Charges on the statements of income, (b) recorded a $30 million provision for refund on the statements of income for revenues previously collected through rates and (c) wrote-off $4 million of rate case expenses to Other Operation on the statements of income. The PUCT is expected to issue an order in the first quarter of 2020. Upon approval of the 2019 Texas Base Rate Case, AEP Texas will refund $275 million of Excess ADIT associated with certain depreciable property using ARAM to transmission customers. AEP Texas will determine how to refund the remaining Excess ADIT that is not subject to normalization requirements in future proceedings. If the final order from the PUCT requires refunds or authorizes disallowances in excess of the amounts included within the February 2020 stipulation and settlement agreement, 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 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 stipulation and settlement agreement discussed in the 2019 Texas Base Rate Case above does not require any adjustments to the remaining $95 million of estimated net transmission-related system restoration costs and these costs will be recovered in base rates if the agreement is approved by the PUCT. 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.

Further amendments to Virginia law impacting investor-owned utilities were enacted, effective July 1, 2018, that require 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 in excess of 70 basis points above APCo’s Virginia SCC authorized ROE would be refunded to customers. In such case, the Virginia SCC could also lower APCo’s Virginia retail base rates on a prospective basis. In November 2018, the Virginia SCC authorized a ROE of 9.42% applicable to APCo base rate earnings for the 2017-2019 triennial period.

Virginia law provides that costs associated with asset impairments of retired coal generation assets, or automated meters, or both, which a utility records as an expense, shall be attributed to the test periods under review in a triennial review proceeding, and be deemed recovered. In 2015, APCo retired the Sporn Plant, the Kanawha River Plant, the Glen Lyn Plant, Clinch River Unit 3 and the coal portions of Clinch River Units 1 and 2 (collectively, the retired coal-fired generation assets). The net book value of these plants at the retirement date was $93 million before cost of removal, including materials and supplies inventory. Based on management’s interpretation of Virginia law and more certainty regarding APCo’s triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets in December 2019. This expense is included in Asset Impairments and Other Related Charges on the statements of income. As a result, management deems these costs to be substantially recovered by APCo during the triennial review period.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately $51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

Inclusive of the $93 million expense associated with APCo's Virginia jurisdictional retired coal-fired plants, APCo estimates its Virginia earnings for the triennial period to be below the authorized ROE range. If any APCo Virginia jurisdictional costs are not recoverable or refunds of revenues collected from customers during the triennial review period, 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 Triennial Review of APCo's earnings, 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 normalization requirements over three years and (d) a one-time credit of $22 million for estimated excess taxes collected from customers as a result of Tax Reform 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 normalization requirements, (c) the utilization of $14 million ($12 million related to APCo) of Excess ADIT that is not subject to 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 semi-annual interim rate changes which are subject to review and possible true-up in the next base rate proceeding. Through December 31, 2019, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $1 billion. 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 base rate proceedings. The rule requires ETT to file for a comprehensive base rate review no later than February 1, 2021.

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

Michigan Tax Reform

In October 2018, I&M made a filing with the MPSC recommending to: (a) refund Excess ADIT associated with certain depreciable property using ARAM and (b) refund Excess ADIT that is not subject to normalization requirements over ten years. In November 2019, the MPSC issued an order authorizing I&M to: (a) refund $48 million of Excess ADIT associated with certain depreciable property using ARAM and (b) refund $28 million of Excess ADIT that is not subject to normalization requirements over ten years. In January 2020, the MPSC issued an order in the 2019 Michigan Base Rate Case that changed the refund period from ten years to five years. See "2019 Michigan Base Rate Case" below.

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 (AMI) 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 intervenors recommended disallowances that could potentially result in write-offs of $41 million related to the remaining book value of existing Indiana jurisdictional meters if I&M is approved to deploy AMI meters as initially requested and $11 million associated with certain Cook Plant study costs.

In September 2019, I&M filed testimony rebutting the various intervenors' recommendations. In October 2019, a hearing at the IURC was held. The IURC is expected to issue an order on this case in 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 January 2020, the MPSC issued an order approving a stipulation and settlement agreement authorizing an annual base rate increase of $36 million based upon a 9.86% return on common equity effective with the first billing cycle of February 2020. The order also requires I&M to amortize and refund to customers through I&M Michigan base rates: (a) Excess ADIT that is not subject to normalization (over a period of five years starting February 2020) and (b) Excess ADIT associated with certain depreciable property using ARAM. Additionally, the order states that I&M will not be allowed to file its next base rate case before 2022.

OPCo Rate Matters (Applies to AEP and OPCo)

Ohio ESP Filings

In 2016, OPCo filed a proposal 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 January 2020, the Ohio Supreme Court affirmed the PUCO order, rejecting the filed appeal.

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. In March 2019, the PUCO staff filed additional comments that OPCo overspent the authorized limit in 2017. 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. In December 2019, the PUCO issued an order finding that OPCo’s 2016 ESRR spending was not subject to an authorized limit. If it is determined OPCo did have an authorized spending limit under the ESRR in 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 Retail Stability Rider 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 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.

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

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant’s Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo’s recovery of AFUDC in addition to limits on its recovery of cash construction costs.

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 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. In the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court.

As of December 31, 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 formula rate plan issues is expected in the first half of 2020.

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 environmental regulations for Welsh Plant, Units 1 and 3 could total approximately $520 million, excluding AFUDC. As of December 31, 2019, SWEPCo had incurred costs of $399 million, including AFUDC, related to these projects. SWEPCo has received approval to recover $340 million of its in-service investments related to environmental controls installed at Welsh Plant through base rates in its Arkansas, Louisiana and Texas jurisdictions. SWEPCo also recovers a portion of its investments related to environmental controls installed at Welsh Plant through wholesale formula rates. See "2016 Texas Base Rate Case," "2018 Louisiana Formula Rate Filing" and "2019 Arkansas Base Rate Case" disclosures for additional information. SWEPCo will seek recovery of future costs that have not yet been approved through base rate cases. If any of the remaining 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 requested rate base treatment for the Stall Plant and environmental retrofits that were 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 included $12 million related to vegetation management to improve the reliability of its Arkansas distribution system. The filing also provided 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 December 2019, the APSC issued an order approving a stipulation and settlement agreement authorizing an 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. The order modified the stipulation and settlement agreement and included a disallowance of $4 million for previously recorded capital incentives. The base rate increase includes $6 million for increased annual depreciation expense and became effective with the first billing cycle in January 2020. The order 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 order also states that SWEPCo's rates will be regulated under the formula rate mechanism authorized by Arkansas law, which includes a Formula Rate Review Rider. Additionally, SWEPCo agreed to make the necessary filings with the APSC, at least 12 months in advance, to seek regulatory approval to retire the Dolet Hills Power Station no later than December 31, 2026.

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 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 were made from the date of the first complaint through December 31, 2018. Refunds for the period prior to 2019 were 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. EFFECTS OF REGULATION

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

Regulated Generating Units to be Retired (Applies to AEP, PSO and SWEPCo)

In September 2018, management announced that the Oklaunion Power Station is probable of abandonment and is to be retired by October 2020. See "2018 Oklahoma Base Rate Case" for additional information.

In January 2020, management announced that the Dolet Hills Power Station is probable of abandonment and is to be retired by December 2026. See "Dolet Hills Lignite Company Operations" section of Executive Overview, "2019 Arkansas Base Rate Case" section of Note 4, and "DHLC" section of Note 17 for additional information.

The table below summarizes the plant investments and their cost of removal, currently being recovered, as well as regulatory assets for accelerated depreciation for the generating units as of December 31, 2019.

Plant	Gross Investment	Accumulated Depreciation	Net Investment	Accelerated Depreciation Regulatory Asset		Materials and Supplies	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
	(dollars in millions)								
Oklaunion Power Station	$ 106.7	$ 86.6	$ 20.1	$ 27.4	(a)	$ 3.2	$ 5.1	2020	27 years
Dolet Hills Power Station	338.9	194.2	144.7	—	(b)	5.8	23.6	2026	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" section of Note 4 for additional information.
(b) Beginning in January 2020, SWEPCo began recording a regulatory asset for accelerated depreciation.

Dolet Hills Power Station and Related Fuel Operations (Applies to AEP and SWEPCo)

During the second quarter of 2019, the Dolet Hills Power Station initiated a seasonal operating schedule. In January 2020, in accordance with the terms of SWEPCo's settlement of its base rate review filed with the APSC, management announced that SWEPCo will seek regulatory approval to retire the Dolet Hills Power Station by the end of 2026. Management also continues to monitor the economic viability of the Dolet Hills Power Station and DHLC mining operations, which may result in a decision to seek permission from appropriate regulatory agencies to discontinue operations earlier than 2026.

The Dolet Hills Power Station costs are recoverable by SWEPCo through base rates. SWEPCo's share of the net investment in the Dolet Hills Power Station is $157 million, including CWIP and materials and supplies, before cost of removal.

Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses. Under the Lignite Mining Agreement, DHLC bills SWEPCo its proportionate share of incurred lignite extraction and associated mining-related costs as fuel is delivered. As of December 31, 2019, DHLC has unbilled fixed costs of $106 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. In 2009, SWEPCo acquired interests in the Oxbow Lignite Company (Oxbow), which owns mineral rights and leases land. Under a Joint Operating Agreement pertaining to the Oxbow mineral rights and land leases, Oxbow bills SWEPCo its proportionate share of incurred costs. As of December 31, 2019, Oxbow has unbilled fixed costs of $22 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. Additional operational and land-related costs are expected to be incurred by DHLC and Oxbow and billed to SWEPCo prior to the closure of the Dolet Hills Power Station and recovered through fuel clauses.

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

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining Recovery Period
	2019	2018	
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 44.7	$ 101.7	1 year
Under-recovered Fuel Costs - does not earn a return	48.2	48.4	1 year
Total Current Regulatory Assets	$ 92.9	$ 150.1	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 35.2	$ 50.3	
Kentucky Deferred Purchased Power Expenses	30.2	14.5	
Oklaunion Power Station Accelerated Depreciation	27.4	5.5	
Other Regulatory Assets Pending Final Regulatory Approval	0.7	9.3	
Total Regulatory Assets Currently Earning a Return	93.5	79.6	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	30.1	35.3	
Vegetation Management Program - AEP Texas (a)	29.4	—	
Cook Plant Study Costs	7.6	—	
Storm-Related Costs (b)	7.2	152.4	
Asset Retirement Obligation - Louisiana	7.2	5.3	
Other Regulatory Assets Pending Final Regulatory Approval	6.7	15.4	
Total Regulatory Assets Currently Not Earning a Return	88.2	208.4	
Total Regulatory Assets Pending Final Regulatory Approval (c)	181.7	288.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	690.5	680.9	23 years
Plant Retirement Costs - Asset Retirement Obligation Costs	87.4	64.3	21 years
Meter Replacement Costs	65.4	74.4	8 years
Environmental Control Projects	41.0	43.4	21 years
Cook Plant Uprate Project	32.6	35.0	14 years
Ohio Distribution Decoupling	31.4	12.3	2 years
Advanced Metering System	26.5	45.3	2 years
Storm-Related Costs	21.3	31.1	3 years
Mitchell Plant Transfer - West Virginia	16.2	17.0	21 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	15.1	16.1	15 years
Cook Plant Turbine	13.4	15.8	19 years
Ohio Capacity Deferral	—	57.8	
Other Regulatory Assets Approved for Recovery	48.4	46.1	various
Total Regulatory Assets Currently Earning a Return	1,089.2	1,139.5	

Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,309.8	1,326.6	11 years
Unamortized Loss on Reacquired Debt	129.0	134.2	29 years
Unrealized Loss on Forward Commitments	106.8	104.6	13 years
Cook Plant Nuclear Refueling Outage Levelization	63.8	37.5	3 years
Vegetation Management - West Virginia	43.6	26.6	2 years
Postemployment Benefits	34.2	35.6	4 years
Plant Retirement Costs - Asset Retirement Obligation Costs	28.8	21.6	23 years
Medicare Subsidy	23.2	27.9	5 years
Peak Demand Reduction/Energy Efficiency	18.6	31.9	7 years
PJM/SPP Annual Formula Rate True Up	7.3	22.0	2 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	—	20.1	
Other Regulatory Assets Approved for Recovery	122.8	94.3	various
Total Regulatory Assets Currently Not Earning a Return	1,887.9	1,882.9	
Total Regulatory Assets Approved for Recovery	2,977.1	3,022.4	
Total Noncurrent Regulatory Assets	$ 3,158.8	$ 3,310.4	

(a) Includes $26 million of deferred expenses from a stipulation and settlement agreement filed in February 2020. See “2019 Texas Base Rate Case” section of Note 4 - Rate Matters for additional information.

(b) 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” section of Note 4 - Rate Matters for additional information.

(c) In 2015, APCo recorded a $91 million reduction, before cost of removal which was $11 million and $20 million as of December 31, 2019 and 2018, respectively, to Accumulated Depreciation and Amortization related to the remaining net book value of coal plants retired in 2015, primarily related to APCo’s Virginia jurisdiction. The net book value of these plants at the retirement date was $93 million before cost of removal, including materials and supplies inventory. Based on management’s interpretation of Virginia law and more certainty regarding APCo’s triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets. This expense is included in Asset Impairments and Other Related Charges on the statements of income.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately $51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

	AEP			
	December 31,		Remaining	
	2019	2018	Refund Period	
Current Regulatory Liabilities	(in millions)			
Over-recovered Fuel Costs - pays a return	$ 77.5	$ 35.7	1 year	
Over-recovered Fuel Costs - does not pay a return	9.1	22.9	1 year	
Total Current Regulatory Liabilities	$ 86.6	$ 58.6		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits				
Regulatory liabilities pending final regulatory determination:				
Regulatory Liabilities Currently Not Paying a Return				
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 0.2	$ 0.2		
Total Regulatory Liabilities Currently Not Paying a Return	0.2	0.2		
Income Tax Related Regulatory Liabilities (a)				
Excess ADIT Associated with Certain Depreciable Property	571.8	1,025.3	(b)	
Excess ADIT that is Not Subject to Rate Normalization Requirements	291.0	695.0	(c) (g)	
Total Income Tax Related Regulatory Liabilities	862.8	1,720.3		
Total Regulatory Liabilities Pending Final Regulatory Determination	863.0	1,720.5		
Regulatory liabilities approved for payment:				
Regulatory Liabilities Currently Paying a Return				
Asset Removal Costs	2,876.7	2,742.8	(d)	
Ohio Basic Transmission Cost Rider	37.2	68.8	2 years	
Excess Earnings	8.3	8.9	34 years	
Deferred Investment Tax Credits	6.2	8.7	41 years	
Other Regulatory Liabilities Approved for Payment	6.1	8.9	various	
Total Regulatory Liabilities Currently Paying a Return	2,934.5	2,838.1		
Regulatory Liabilities Currently Not Paying a Return				
Excess Nuclear Decommissioning Funding	1,236.0	828.5	(e)	
Deferred Investment Tax Credits	215.3	204.9	43 years	
PJM Transmission Enhancement Refund	67.3	164.2	6 years	
Transition and Restoration Charges - Texas	50.5	46.0	10 years	
Spent Nuclear Fuel	43.6	42.9	(e)	
Ohio Enhanced Service Reliability Plan	29.7	43.1	2 years	
Virginia Transmission Rate Adjustment Clause	28.1	11.3	2 years	
Deferred Gain on Sale of Rockport Unit 2	27.2	—	3 years	
Peak Demand Reduction/Energy Efficiency	23.0	17.5	2 years	
Unrealized Gain on Forward Commitments	17.7	45.9	5 years	
Other Regulatory Liabilities Approved for Payment	70.0	73.5	various	
Total Regulatory Liabilities Currently Not Paying a Return	1,808.4	1,477.8		
Income Tax Related Regulatory Liabilities (a)				
Excess ADIT Associated with Certain Depreciable Property	3,303.0	2,925.7	(f)	
Excess ADIT that is Not Subject to Rate Normalization Requirements	890.5	864.3	17 years	
Income Taxes Subject to Flow Through	(1,341.8)	(1,286.1)	56 years	
Total Income Tax Related Regulatory Liabilities	2,851.7	2,503.9		
Total Regulatory Liabilities Approved for Payment	7,594.6	6,819.8		
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 8,457.6	$ 8,540.3		

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.

(b) Includes $275 million that will be refunded using ARAM upon receiving an order in the 2019 Texas Base Rate Case. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information.

(c) Includes $71 million from a stipulation and settlement agreement filed in February 2020. See “2019 Texas Base Rate Case” section of Note 4 - Rate Matters for additional information.

(d) Relieved as removal costs are incurred.

(e) Relieved when plant is decommissioned.

(f) Refunded using ARAM.

(g) 2019 and 2018 amounts include approximately $172 million related to AEP Transmission Holdco’s investment in ETT and Transource Energy. AEP Transmission Holdco expects to amortize the balance commensurate with the return of Excess ADIT to ETT and Transource Energy’s customers.

Regulatory Assets:	AEP Texas December 31, 2019	AEP Texas December 31, 2018	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Vegetation Management Program (a)	$ 29.4	$ —	
Storm-Related Costs (b)	—	152.4	
Other Regulatory Assets Pending Final Regulatory Approval	1.4	0.2	
Total Regulatory Assets Pending Final Regulatory Approval	30.8	152.6	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Meter Replacement Costs	35.2	40.1	8 years
Advanced Metering System	26.5	45.3	2 years
Total Regulatory Assets Currently Earning a Return	61.7	85.4	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	172.0	176.9	11 years
Unamortized Loss on Reacquired Debt	6.4	6.0	18 years
Other Regulatory Assets Approved for Recovery	9.7	9.1	various
Total Regulatory Assets Currently Not Earning a Return	188.1	192.0	
Total Regulatory Assets Approved for Recovery	249.8	277.4	
Total Noncurrent Regulatory Assets	$ 280.6	$ 430.0	

(a) Includes $26 million of deferred expenses from a stipulation and settlement agreement filed in February 2020. See “2019 Texas Base Rate Case” section of Note 4 - Rate Matters for additional information.

(b) 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” section of Note 4 - Rate Matters for additional information.

Regulatory Liabilities:	AEP Texas December 31, 2019	AEP Texas December 31, 2018	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 274.9	$ 277.1	(b)
Excess ADIT that is Not Subject to Rate Normalization Requirements	87.1	141.4	(c)
Total Regulatory Liabilities Pending Final Regulatory Determination	362.0	418.5	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	689.6	645.2	(d)
Excess Earnings	5.8	6.3	12 years
Advanced Metering Infrastructure Surcharge	4.3	8.5	1 year
Total Regulatory Liabilities Currently Paying a Return	699.7	660.0	
Regulatory Liabilities Currently Not Paying a Return			
Transition and Restoration Charges	50.5	46.0	10 years
Deferred Investment Tax Credits	9.6	10.8	43 years
Other Regulatory Liabilities Approved for Payment	4.8	—	various
Total Regulatory Liabilities Currently Not Paying a Return	64.9	56.8	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	236.5	251.8	(e)
Income Taxes Subject to Flow Through	(46.2)	(42.8)	13 years
Total Income Tax Related Regulatory Liabilities	190.3	209.0	
Total Regulatory Liabilities Approved for Payment	954.9	925.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,316.9	$ 1,344.3	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Will be refunded using ARAM upon receiving an order in the 2019 Texas Base Rate Case. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information.
(c) Includes $71 million from a stipulation and settlement agreement filed in February 2020. See "2019 Texas Base Rate Case" section of Note 4 - Rate Matters for additional information.
(d) Relieved as removal costs are incurred.
(e) Refunded using ARAM.

Regulatory Assets:	AEPTCo December 31, 2019	AEPTCo December 31, 2018	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets approved for recovery:			
Regulatory Assets Currently Not Earning a Return			
PJM/SPP Annual Formula Rate True Up	$ 4.2	$ 12.9	2 years
Total Regulatory Assets Approved for Recovery	4.2	12.9	
Total Noncurrent Regulatory Assets	$ 4.2	$ 12.9	

Regulatory Liabilities:	AEPTCo December 31, 2019	AEPTCo December 31, 2018	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ —	$ 73.9	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	4.5	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	78.4	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	141.0	99.5	(b)
Total Regulatory Liabilities Currently Paying a Return	141.0	99.5	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	535.7	453.4	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	(35.4)	(28.5)	9 years
Income Taxes Subject to Flow Through	(100.4)	(81.5)	44 years
Total Income Tax Related Regulatory Liabilities	399.9	343.4	
Total Regulatory Liabilities Approved for Payment	540.9	442.9	
Total Noncurrent Regulatory Liabilities	$ 540.9	$ 521.3	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See “Federal Tax Reform” section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	APCo December 31, 2019	2018	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Virginia - earns a return	$ 36.8	$ 82.4	1 year
Under-recovered Fuel Costs, West Virginia - does not earn a return	5.7	17.2	1 year
Total Current Regulatory Assets	$ 42.5	$ 99.6	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Materials and Supplies	$ 0.5	$ 9.0	
Total Regulatory Assets Currently Earning a Return	0.5	9.0	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	30.1	35.3	
Other Regulatory Assets Pending Final Regulatory Approval	—	0.6	
Total Regulatory Assets Currently Not Earning a Return	30.1	35.9	
Total Regulatory Assets Pending Final Regulatory Approval (a)	30.6	44.9	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant - West Virginia	86.4	85.3	24 years
Other Regulatory Assets Approved for Recovery	0.5	1.2	various
Total Regulatory Assets Currently Earning a Return	86.9	86.5	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	160.8	172.2	11 years
Unamortized Loss on Reacquired Debt	85.5	89.3	23 years
Vegetation Management Program - West Virginia	43.6	26.6	2 years
Peak Demand Reduction/Energy Efficiency	19.5	19.7	7 years
Postemployment Benefits	15.9	18.0	4 years
Virginia Generation Rate Adjustment Clause	5.1	10.3	2 years
Other Regulatory Assets Approved for Recovery	9.3	8.3	various
Total Regulatory Assets Currently Not Earning a Return	339.7	344.4	
Total Regulatory Assets Approved for Recovery	426.6	430.9	
Total Noncurrent Regulatory Assets	$ 457.2	$ 475.8	

(a) In 2015, APCo recorded a $91 million reduction, before cost of removal which was $11 million and $20 million as of December 31, 2019 and 2018, respectively, to Accumulated Depreciation and Amortization related to the remaining net book value of coal plants retired in 2015, primarily related to APCo's Virginia jurisdiction. The net book value of these plants at the retirement date was $93 million before cost of removal, including materials and supplies inventory. Based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation assets. This expense is included in Asset Impairments and Other Related Charges on the statements of income.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with Advanced Metering Infrastructure (AMI) meters. As of December 31, 2019, APCo has approximately $51 million of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo intends to pursue full recovery of these assets through future depreciation rates.

Regulatory Liabilities:	APCo December 31, 2019	2018	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ —	$ 268.2	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	283.7	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	551.9	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	635.3	618.3	(b)
Deferred Investment Tax Credits	0.5	1.0	41 years
Total Regulatory Liabilities Currently Paying a Return	635.8	619.3	
Regulatory Liabilities Currently Not Paying a Return			
Virginia Transmission Rate Adjustment Clause	28.1	11.3	2 years
PJM Transmission Enhancement Refund	19.5	47.7	6 years
Unrealized Gain on Forward Commitments	9.3	34.7	5 years
Consumer Rate Relief - West Virginia	5.4	8.8	1 year
Other Regulatory Liabilities Approved for Payment	3.3	3.9	various
Total Regulatory Liabilities Currently Not Paying a Return	65.6	106.4	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	718.9	453.5	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	210.7	84.5	9 years
Income Taxes Subject to Flow Through	(362.3)	(365.9)	23 years
Total Income Tax Related Regulatory Liabilities	567.3	172.1	
Total Regulatory Liabilities Approved for Payment	1,268.7	897.8	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,268.7	$ 1,449.7	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	I&M December 31, 2019	2018	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 3.0	$ —	1 Year
Total Current Regulatory Assets	$ 3.0	$ —	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Cook Plant Study Costs	$ 7.6	$ —	
Other Regulatory Assets Pending Final Regulatory Approval	0.1	3.3	
Total Regulatory Assets Pending Final Regulatory Approval	7.7	3.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	214.9	232.2	9 years
Cook Plant Uprate Project	32.6	35.0	14 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	15.1	16.1	15 years
Cook Plant Turbine	13.4	15.8	19 years
Rockport Plant Dry Sorbent Injection System - Indiana	10.2	11.5	8 years
Cook Plant, Unit 2 Baffle Bolts - Indiana	5.4	5.7	19 years
Other Regulatory Assets Approved for Recovery	4.8	2.4	various
Total Regulatory Assets Currently Earning a Return	296.4	318.7	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	67.5	84.9	11 years
Cook Plant Nuclear Refueling Outage Levelization	63.8	37.5	3 years
Unamortized Loss on Reacquired Debt	17.2	18.7	29 years
Postemployment Benefits	7.2	6.5	4 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	—	20.1	
Other Regulatory Assets Approved for Recovery	22.3	22.8	various
Total Regulatory Assets Currently Not Earning a Return	178.0	190.5	
Total Regulatory Assets Approved for Recovery	474.4	509.2	
Total Noncurrent Regulatory Assets	$ 482.1	$ 512.5	

Regulatory Liabilities:	I&M December 31, 2019	I&M December 31, 2018	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, Michigan - pays a return	$ —	$ 4.5	
Over-recovered Fuel Costs, Indiana - does not pay a return	6.1	22.9	1 year
Total Current Regulatory Liabilities	$ 6.1	$ 27.4	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ —	$ 125.0	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	40.6	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	165.6	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	166.7	182.5	(b)
Other Regulatory Liabilities Approved for Payment	0.3	—	various
Total Regulatory Liabilities Currently Paying a Return	167.0	182.5	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,236.0	828.5	(c)
Spent Nuclear Fuel	43.6	42.9	(c)
Deferred Investment Tax Credits	25.8	29.4	20 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	17.0	—	2 years
PJM Transmission Enhancement Refund	11.8	29.1	6 years
Deferred Gain on Sale of Rockport Unit 2	10.9	—	3 years
Other Regulatory Liabilities Approved for Payment	24.9	24.0	various
Total Regulatory Liabilities Currently Not Paying a Return	1,370.0	953.9	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	470.9	362.0	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	184.5	192.6	5 years
Income Taxes Subject to Flow Through	(301.0)	(282.1)	19 years
Total Income Tax Related Regulatory Liabilities	354.4	272.5	
Total Regulatory Liabilities Approved for Payment	1,891.4	1,408.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,891.4	$ 1,574.5	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Relieved when plant is decommissioned.
(d) Refunded using ARAM.

Regulatory Assets:	OPCo December 31, 2019	2018	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ —	$ 0.4	
Total Current Regulatory Assets	$ —	$ 0.4	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
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	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Ohio Distribution Decoupling	31.4	12.3	2 years
Ohio Capacity Deferral	—	57.8	
Other Regulatory Assets Approved for Recovery	—	0.9	
Total Regulatory Assets Currently Earning a Return	31.4	71.0	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	167.3	181.5	11 years
Unrealized Loss on Forward Commitments	103.6	100.2	13 years
Smart Grid Costs	13.7	8.1	2 years
Distribution Investment Rider	10.9	—	2 years
Postemployment Benefits	7.6	7.9	4 years
Unamortized Loss on Reacquired Debt	5.3	6.5	19 years
Other Regulatory Assets Approved for Recovery	11.9	11.3	various
Total Regulatory Assets Currently Not Earning a Return	320.3	315.5	
Total Regulatory Assets Approved for Recovery	351.7	386.5	
Total Noncurrent Regulatory Assets	$ 351.8	$ 387.5	

Regulatory Liabilities:	OPCo December 31, 2019	OPCo December 31, 2018	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - does not pay a return	$ 2.8	$ —	1 year
Total Current Regulatory Liabilities	$ 2.8	$ —	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 0.2	$ 0.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	0.2	0.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	446.3	436.6	(b)
Ohio Basic Transmission Cost Rider	37.2	68.8	2 years
Other Regulatory Liabilities Approved for Payment	1.3	0.4	various
Total Regulatory Liabilities Currently Paying a Return	484.8	505.8	
Regulatory Liabilities Currently Not Paying a Return			
Ohio Enhanced Service Reliability Plan	29.7	43.1	2 years
PJM Transmission Enhancement Refund	29.4	71.3	6 years
Peak Demand Reduction/Energy Efficiency	19.7	14.9	2 years
Distribution Investment Rider	—	7.8	
Other Regulatory Liabilities Approved for Payment	2.9	11.3	various
Total Regulatory Liabilities Currently Not Paying a Return	81.7	148.4	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	341.6	350.5	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	252.3	279.1	9 years
Income Taxes Subject to Flow Through	(69.7)	(62.8)	28 years
Total Income Tax Related Regulatory Liabilities	524.2	566.8	
Total Regulatory Liabilities Approved for Payment	1,090.7	1,221.0	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,090.9	$ 1,221.2	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See “Federal Tax Reform” section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

	PSO		
	December 31,		Remaining Recovery Period
	2019	2018	
Regulatory Assets:	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Oklaunion Power Station Accelerated Depreciation	$ 27.4	$ 5.5	
Total Regulatory Assets Currently Earning a Return	27.4	5.5	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	7.2	—	
Other Regulatory Assets Pending Final Regulatory Approval	—	0.5	
Total Regulatory Assets Currently Not Earning a Return	7.2	0.5	
Total Regulatory Assets Pending Final Regulatory Approval	34.6	6.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	167.0	153.4	21 years
Meter Replacement Costs	30.2	34.3	8 years
Environmental Control Projects	27.8	29.2	21 years
Storm-Related Costs	21.3	31.1	3 years
Red Rock Generating Facility	8.4	8.6	37 years
Other Regulatory Assets Approved for Recovery	0.6	0.5	various
Total Regulatory Assets Currently Earning a Return	255.3	257.1	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	73.4	84.3	11 years
Unamortized Loss on Reacquired Debt	6.5	4.3	15 years
Peak Demand Reduction/Energy Efficiency	—	6.3	
Other Regulatory Assets Approved for Recovery	5.4	11.0	various
Total Regulatory Assets Currently Not Earning a Return	85.3	105.9	
Total Regulatory Assets Approved for Recovery	340.6	363.0	
Total Noncurrent Regulatory Assets	$ 375.2	$ 369.0	

	PSO		
	December 31,		Remaining Refund Period
	2019	2018	
Regulatory Liabilities:	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	$ 63.9	$ 20.1	1 year
Total Current Regulatory Liabilities	$ 63.9	$ 20.1	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 286.8	$ 276.8	(b)
Total Regulatory Liabilities Currently Paying a Return	286.8	276.8	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	51.5	51.5	25 years
Other Regulatory Liabilities Approved for Payment	4.7	2.5	various
Total Regulatory Liabilities Currently Not Paying a Return	56.2	54.0	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	405.8	415.2	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	96.3	126.4	5 years
Income Taxes Subject to Flow Through	(7.9)	(7.7)	24 years
Total Income Tax Related Regulatory Liabilities	494.2	533.9	
Total Regulatory Liabilities Approved for Payment	837.2	864.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 837.2	$ 864.7	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

	SWEPCo		
	December 31,		Remaining Recovery Period
	2019	2018	
Regulatory Assets:	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return (a)	$ 4.9	$ 18.8	1 year
Total Current Regulatory Assets	$ 4.9	$ 18.8	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant, Louisiana	$ 35.2	$ 50.3	
Other Regulatory Assets Pending Final Regulatory Approval	0.2	0.3	
Total Regulatory Assets Currently Earning a Return	35.4	50.6	
Regulatory Assets Currently Not Earning a Return			
Asset Retirement Obligation - Louisiana	7.2	5.3	
Rate Case Expense - Texas	1.0	4.9	
Other Regulatory Assets Pending Final Regulatory Approval	2.7	3.6	
Total Regulatory Assets Currently Not Earning a Return	10.9	13.8	
Total Regulatory Assets Pending Final Regulatory Approval	46.3	64.4	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant, Arkansas	15.1	—	23 years
Environmental Controls Projects	13.2	14.2	13 years
Other Regulatory Assets Approved for Recovery	8.9	7.2	various
Total Regulatory Assets Currently Earning a Return	37.2	21.4	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	102.6	108.4	11 years
Plant Retirement Costs - Unrecovered Plant, Texas	16.6	17.1	22 years
Unamortized Loss on Reacquired Debt	6.6	7.4	24 years
Rate Case Expense - Arkansas	5.2	0.8	5 years
Other Regulatory Assets Approved for Recovery	7.9	11.3	various
Total Regulatory Assets Currently Not Earning a Return	138.9	145.0	
Total Regulatory Assets Approved for Recovery	176.1	166.4	
Total Noncurrent Regulatory Assets	$ 222.4	$ 230.8	

(a) December 31, 2019 amount includes Arkansas jurisdiction. December 31, 2018 amount includes Arkansas and Louisiana jurisdictions.

	SWEPCo		
	December 31,		Remaining Refund Period
	2019	2018	
Regulatory Liabilities:	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return (a)	$ 13.6	$ 11.1	1 year
Total Current Regulatory Liabilities	$ 13.6	$ 11.1	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (b)			
Excess ADIT Associated with Certain Depreciable Property	$ 297.0	$ 280.1	
Excess ADIT that is Not Subject to Rate Normalization Requirements	22.7	26.9	
Total Regulatory Liabilities Pending Final Regulatory Determination	319.7	307.0	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	453.4	437.8	(c)
Other Regulatory Liabilities Approved for Payment	2.8	2.5	various
Total Regulatory Liabilities Currently Paying a Return	456.2	440.3	
Regulatory Liabilities Currently Not Paying a Return			
Peak Demand Reduction/Energy Efficiency	6.0	2.5	2 years
Deferred Investment Tax Credits	3.1	4.5	12 years
Other Regulatory Liabilities Approved for Payment	1.7	2.4	various
Total Regulatory Liabilities Currently Not Paying a Return	10.8	9.4	
Income Tax Related Regulatory Liabilities (b)			
Excess ADIT Associated with Certain Depreciable Property	339.4	370.5	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	27.8	54.3	1 year
Income Taxes Subject to Flow Through	(261.6)	(258.5)	28 years
Total Income Tax Related Regulatory Liabilities	105.6	166.3	
Total Regulatory Liabilities Approved for Payment	572.6	616.0	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 892.3	$ 923.0	

(a) December 31, 2019 amount includes Texas and Louisiana jurisdictions. December 31, 2018 amount includes Texas jurisdiction.
(b) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(c) Relieved as removal costs are incurred.
(d) Refunded using ARAM.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

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

COMMITMENTS (Applies to all Registrants except AEP Texas and AEPTCo)

The AEP System has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following tables summarize the Registrants' actual contractual commitments as of December 31, 2019:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 1,047.0	$ 1,105.0	$ 234.4	$ 111.4	$ 2,497.8
Energy and Capacity Purchase Contracts	227.8	353.2	273.5	1,080.0	1,934.5
Total	$ 1,274.8	$ 1,458.2	$ 507.9	$ 1,191.4	$ 4,432.3

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 415.3	$ 369.2	$ 4.6	$ 0.3	$ 789.4
Energy and Capacity Purchase Contracts	35.4	72.1	73.7	275.5	456.7
Total	$ 450.7	$ 441.3	$ 78.3	$ 275.8	$ 1,246.1

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 299.8	$ 340.7	$ 211.6	$ 67.2	$ 919.3
Energy and Capacity Purchase Contracts	151.0	340.5	60.4	289.2	841.1
Total	$ 450.8	$ 681.2	$ 272.0	$ 356.4	$ 1,760.4

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 29.0	$ 58.6	$ 58.8	$ 302.5	$ 448.9

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 52.3	$ 42.8	$ —	$ —	$ 95.1
Energy and Capacity Purchase Contracts	93.0	132.3	65.2	193.3	483.8
Total	$ 145.3	$ 175.1	$ 65.2	$ 193.3	$ 578.9

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 130.4	$ 147.4	$ 4.5	$ —	$ 282.3
Energy and Capacity Purchase Contracts	14.0	12.5	8.4	8.4	43.3
Total	$ 144.4	$ 159.9	$ 12.9	$ 8.4	$ 325.6

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

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 December 31, 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 December 31, 2019 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 206.8	January 2020 to December 2020
AEP Texas	2.2	July 2020
OPCo	1.6	April 2020 to September 2020

Guarantees of Equity Method Investees (Applies to AEP)

In April 2019, AEP acquired Sempra Renewables LLC. See "Acquisitions" section of Note 7 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 December 31, 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.

Lease Obligations

Certain Registrants lease equipment under master lease agreements. See "Master Lease Agreements" and "AEPRO Boat and Barge Leases" sections of Note 13 for additional information.

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.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2019, APCo, OPCo and SWEPCo are named as a Potentially Responsible Party (PRP) for one, three, and one sites, respectively, by the Federal EPA for which alleged liability is unresolved. There are 11 additional sites for which APCo, I&M, KPCo, OPCo and SWEPCo received information requests which could lead to PRP designation. I&M has also been named potentially liable at three sites under state law. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2019, management's estimates do not anticipate material clean-up costs for identified Superfund sites.

NUCLEAR CONTINGENCIES (APPLIES TO AEP AND I&M)

I&M owns and operates the two-unit 2,288 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Decommissioning and Low-Level Waste Accumulation Disposal

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2018. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste was $2 billion in 2018 non-discounted dollars, with additional ongoing costs of $6 million per year for post decommissioning storage of SNF and an eventual cost of $37 million for the subsequent decommissioning of the SNF storage facility, also in 2018 non-discounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $7 million, $8 million and $9 million for the years ended December 31, 2019, 2018 and 2017, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2019 and 2018, the total decommissioning trust fund balances were $2.7 billion and $2.2 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from customers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

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

Spent Nuclear Fuel Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to $0. As of December 31, 2019 and 2018, fees and related interest of $280 million and $274 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Long-term Debt and funds collected from customers along with related earnings totaling $323 million and $317 million, respectively, to pay the fee were recorded as part of Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received $8 million, $11 million and $22 million in 2019, 2018 and 2017, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2019. The proceeds reduced costs for dry cask storage. As of December 31, 2019 and 2018, I&M deferred $24 million and $8 million, respectively, in Prepayments and Other Current Assets and $1 million and $23 million, respectively, in Deferred Charges and Other Noncurrent Assets on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for additional information.

Nuclear Insurance

I&M carries nuclear property insurance of $2.7 billion to cover an incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by an extraordinary incident. Insurance coverage for a nonnuclear property incident at Cook Plant is $1 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $47 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $13.9 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $450 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $275 million per nuclear incident on Cook Plant's reactors payable in annual installments of $41 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $450 million through commercially available insurance. The next level of liability coverage of up to $13.5 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

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

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

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

In 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. The district court entered a stay that expired in February 2020. Settlement negotiations are continuing, and the parties filed a joint proposed case schedule in February 2020. 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 is 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 losses that is reasonably possible of occurring.

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

The American Electric Power System Retirement Plan (the Plan) has received a letter written on behalf of four participants (the Claimants) making a claim for additional plan benefits and purporting to advance such claims on behalf of a class. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The Claimants have asserted claims that (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career; (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act (ADEA); and (c) the company failed to provide required notice regarding the changes to the Plan. AEP has responded to the Claimants providing a reasoned explanation for why each of their claims have been denied, and offering an opportunity to appeal those determinations. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

7. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

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

ACQUISITIONS

2019

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 $580 million in cash and acquired a 50% ownership interest in five non-consolidated joint ventures with net assets valued at $404 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 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	$	8.8	Current Liabilities	$	12.9	
Property, Plant and Equipment		238.1	Asset Retirement Obligations		5.7	
Investment in Joint Ventures		404.0	**Total Liabilities**		18.6	
Other Noncurrent Assets		82.9	Noncontrolling Interest		134.8	
Total Assets	$	733.8	**Liabilities and Noncontrolling Interest**	$	153.4	$ 580.4

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 PPAs, forecasted market power prices, expected wind farm net capacity and discount rates reflecting risk inherent in the future cash flows and future power prices. Estimating forecasted market power prices involved determining the cost of constructing and operating a new wind plant over an assumed life in the same geographic region as of the acquisition date using third-party market participant assumptions. The expected wind farm net capacity was developed by evaluating each wind farm's historical and expected generation against historical generation of comparable wind farms in the same locations. Discount rates were evaluated by considering the cost of capital of comparable businesses. 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 $9 million and $17 million, respectively, for the year ended December 31, 2019. Another joint venture wind farm has a PPA with SWEPCo for a portion of its energy production which totaled $10 million of purchased electricity for the year ended December 31, 2019. 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 December 31, 2019, the maximum potential amount of future payments associated with these guarantees was $175 million, with the last guarantee expiring in December 2037. The liability recorded associated with these guarantees was $34 million as of December 31, 2019.

The acquired business contributed revenues and net income to AEP that were not material for the period April 22, 2019 to December 31, 2019. The pro-forma revenue and net income related to the acquisition of Sempra Renewables LLC were not material for the year ended December 31, 2019.

See Note 17 - 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 17 for additional information.

DISPOSITIONS

2017

Zimmer Plant (Generation & Marketing Segment)

In February 2017, AEP signed an agreement to sell its 25.4% ownership share of Zimmer Plant to a nonaffiliated party. The transaction closed in the second quarter of 2017 and did not have a material impact on net income, cash flows or financial condition. The Income before Income Tax Expense and Equity Earnings of Zimmer Plant was immaterial for the years ended December 31, 2017 and 2016.

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

In September 2016, AEP signed a Purchase and Sale Agreement to sell AGR's Gavin, Waterford and Darby Plants as well as AEGCo's Lawrenceburg Plant totaling 5,329 MWs of competitive generation assets to a nonaffiliated party. The sale closed in January 2017 for $2.2 billion, which was recorded in Investing Activities on the statements of cash flows. The net proceeds from the transaction were $1.2 billion in cash after taxes, repayment of debt associated with these assets including a make whole payment related to the debt, payment of a coal contract associated with one of the plants and transaction fees. The sale resulted in a pretax gain of $226 million that was recorded in Gain on Sale of Merchant Generation Assets on AEP's statements of income for the year ended December 31, 2017.

IMPAIRMENTS

2019

2019 Texas Base Rate Case (Transmission and Distribution Segment) (Applies to AEP and AEP Texas)

In December 2019, AEP Texas recorded a pretax impairment of $33 million in Asset Impairments and Other Related Charges on the statements of income due to regulatory disallowances in the 2019 Texas Base Rate Case. See “2019 Texas Base Rate Case” section of Note 4 for additional information.

Virginia Jurisdictional Book Value of Retired Coal-Fired Plants (Vertically Integrated Utilities Segment) (Applies to AEP and APCo)

In December 2019, based on management’s interpretation of Virginia law and more certainty regarding APCo’s triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million related to its previously retired coal-fired generation. This expense is recorded in Asset Impairments and Other Related Charges on the statements of income. See “Virginia Legislation Affecting Earnings Reviews” section of Note 4 for additional information.

Merchant Generating Assets (Generation & Marketing Segment)

Due to a significant increase in the asset retirement costs recorded in December 2019 for the Ash Pond Complex at Conesville Plant, AEP performed an impairment analysis on Conesville Plant in accordance with accounting guidance for impairments of long-lived assets. AEP performed step one and step two of the impairment analysis using a cash flow model for the estimated useful life of Conesville Plant based upon energy and capacity price curves, which were developed internally with both observable Level 2 third-party quotations and unobservable Level 3 inputs, as well as management’s forecasts of operating expenses. The step two analysis resulted in a fair value determination for Conesville Plant of $0 and AEP recorded a $31 million pretax impairment, equal to the net book value of the plant, in Asset Impairments and Other Related Charges on AEP’s statements of income in the fourth quarter of 2019.

2018

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 Asset Impairments and Other Related Charges 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 and reconstruction activities continued throughout 2018. An initial impairment recorded related to Racine is discussed in the “2017” section below.

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.

Reconstruction activities at Racine are currently 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.

2017

Merchant Generating Assets (Generation & Marketing Segment)

In 2017, AEP recorded an additional pretax impairment of $4 million in Asset Impairments and Other Related Charges on AEP's statements of income related to Cardinal, Unit 1, a 43.5% interest in Conesville, Unit 4, Conesville, Units 5 and 6, a 26% interest in Stuart, Units 1-4, a 25.4% interest in Zimmer, Unit 1, and a 54.7% interest in Oklaunion (collectively the "Merchant Coal-Fired Generation Assets"). In addition, AEP recorded a $7 million pretax impairment as Asset Impairments and Other Related Charges on AEP's statements of income related to the sale of Zimmer Plant. The sale is further discussed in the "Disposition" section of this note.

Due to a significant increase in estimated costs identified in December 2017 to repair a defective dam structure at Racine, AEP performed an impairment analysis on Racine in accordance with accounting guidance for impairments of long-lived assets. 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 both 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 fair value determination for Racine of $0 and AEP recorded a pretax impairment of $43 million in Assets Impairments and Other Related Charges on the statements of income in the fourth quarter of 2017.

Welsh Plant, Unit 2 and Turk Plant (Vertically Integrated Utilities Segment) (Applies to AEP and SWEPCo)

In December 2017, SWEPCo recorded a pretax impairment of $19 million in Asset Impairments and Other Related Charges on the statements of income related to the Texas jurisdictional share of Welsh Plant, Unit 2 and other disallowed plant investments. Additionally in December 2017, SWEPCo recorded a pretax impairment of $15 million in Asset Impairments and Other Related Charges on the statements of income related to the Louisiana jurisdictional share of the Turk Plant. See the "2016 Texas Base Rate Case" section of Note 4.

8. BENEFIT PLANS

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

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

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

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

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

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		OPEB	
	December 31,			
Assumption	**2019**	**2018**	**2019**	**2018**
Discount Rate	3.25%	4.30%	3.30%	4.30%
Interest Crediting Rate	4.00%	4.00%	NA	NA

NA Not applicable.

	Pension Plans	
	December 31,	
Assumption – Rate of Compensation Increase (a)	**2019**	**2018**
AEP	4.95%	4.85%
AEP Texas	5.00%	4.95%
APCo	4.80%	4.75%
I&M	4.95%	4.90%
OPCo	5.15%	5.00%
PSO	5.05%	4.90%
SWEPCo	4.90%	4.85%

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

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

For 2019, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrants' population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			OPEB		
	Year Ended December 31,					
Assumption	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Discount Rate	4.30%	3.65%	4.05%	4.30%	3.60%	4.10%
Interest Crediting Rate	4.00%	4.00%	4.00%	NA	NA	NA
Expected Return on Plan Assets	6.25%	6.00%	6.00%	6.25%	6.00%	6.75%

NA Not applicable.

	Pension Plans		
	Year Ended December 31,		
Assumption – Rate of Compensation Increase (a)	**2019**	**2018**	**2017**
AEP	4.95%	4.85%	4.80%
AEP Texas	5.00%	4.95%	4.90%
APCo	4.75%	4.75%	4.60%
I&M	4.95%	4.90%	4.85%
OPCo	5.20%	5.00%	4.95%
PSO	5.05%	4.90%	4.90%
SWEPCo	4.90%	4.85%	4.80%

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

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

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

	December 31,	
Health Care Trend Rates	**2019**	**2018**
Initial	6.00%	6.25%
Ultimate	4.50%	5.00%
Year Ultimate Reached	2026	2024

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2019, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets, Funded Status and Amounts Recognized on the Balance Sheets

For the year ended December 31, 2019, the pension plans had an actuarial loss due to a decrease in the discount rate, partially offset by updates to the mortality table. For the year ended December 31, 2019, the OPEB plans had an actuarial loss due to a decrease in the discount rate and an update to the persistency assumption, partially offset by an update to the projected per capita cost assumption as well as savings resulting from legislation signed in December 2019 which eliminated two Affordable Care Act taxes. For the year ended December 31, 2018, the pension and OPEB plans had an actuarial gain due to an increase in the discount rate as well as updated estimates for future medical expenses in the OPEB plans. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

AEP	**Pension Plans**		**OPEB**	
	2019	**2018**	**2019**	**2018**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 4,810.3	$ 5,215.8	$ 1,194.5	$ 1,332.0
Service Cost	95.5	97.6	9.5	11.6
Interest Cost	204.4	187.8	50.5	47.4
Actuarial (Gain) Loss	493.6	(306.3)	58.8	(100.1)
Plan Amendments	0.2	—	(11.0)	—
Benefit Payments	(367.2)	(384.6)	(113.0)	(133.6)
Participant Contributions	—	—	35.5	36.5
Medicare Subsidy	—	—	0.6	0.7
Benefit Obligation as of December 31,	$ 5,236.8	$ 4,810.3	$ 1,225.4	$ 1,194.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 4,695.9	$ 5,174.1	$ 1,534.2	$ 1,732.5
Actual Gain (Loss) on Plan Assets	681.1	(104.9)	321.0	(118.3)
Company Contributions (a)	5.6	11.3	4.1	17.1
Participant Contributions	—	—	35.5	36.5
Benefit Payments	(367.2)	(384.6)	(113.0)	(133.6)
Fair Value of Plan Assets as of December 31,	$ 5,015.4	$ 4,695.9	$ 1,781.8	$ 1,534.2
Funded (Underfunded) Status as of December 31,	$ (221.4)	$ (114.4)	$ 556.4	$ 339.7

(a) AEP did not make contributions to the qualified pension plan in 2019 or 2018. Contributions to the nonqualified pension plans were $6 million and $11 million for the years ended December 31, 2019 and 2018, respectively.

AEP	**Pension Plans**		**OPEB**	
	December 31,			
	2019	**2018**	**2019**	**2018**
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 590.8	$ 392.2
Other Current Liabilities – Accrued Short-term Benefit Liability	(6.1)	(5.7)	(2.6)	(2.8)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(215.3)	(108.7)	(31.8)	(49.7)
Funded (Underfunded) Status	$ (221.4)	$ (114.4)	$ 556.4	$ 339.7

AEP Texas	**Pension Plans**		**OPEB**	
	2019	**2018**	**2019**	**2018**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 409.3	$ 441.3	$ 95.9	$ 107.1
Service Cost	8.6	9.2	0.8	0.9
Interest Cost	17.5	16.0	4.0	3.8
Actuarial (Gain) Loss	40.1	(20.9)	3.9	(8.3)
Plan Amendments	—	—	(0.9)	—
Benefit Payments	(34.3)	(36.3)	(8.8)	(10.7)
Participant Contributions	—	—	2.9	3.1
Benefit Obligation as of December 31,	$ 441.2	$ 409.3	$ 97.8	$ 95.9
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 410.7	$ 455.9	$ 129.9	$ 147.3
Actual Gain (Loss) on Plan Assets	58.3	(9.3)	24.0	(14.6)
Company Contributions	0.4	0.4	0.1	4.8
Participant Contributions	—	—	2.9	3.1
Benefit Payments	(34.3)	(36.3)	(8.8)	(10.7)
Fair Value of Plan Assets as of December 31,	$ 435.1	$ 410.7	$ 148.1	$ 129.9
Funded (Underfunded) Status as of December 31,	$ (6.1)	$ 1.4	$ 50.3	$ 34.0

AEP Texas	**Pension Plans**		**OPEB**	
	December 31,			
	2019	**2018**	**2019**	**2018**
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ 5.2	$ 50.3	$ 34.0
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.4)	(0.4)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(5.7)	(3.4)	—	—
Funded (Underfunded) Status	$ (6.1)	$ 1.4	$ 50.3	$ 34.0

APCo	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 603.1	$ 665.0	$ 205.5	$ 236.5
Service Cost	9.4	9.3	1.0	1.1
Interest Cost	25.2	23.5	8.7	8.2
Actuarial (Gain) Loss	52.9	(49.2)	4.7	(21.9)
Plan Amendments	—	—	(1.7)	—
Benefit Payments	(43.4)	(45.5)	(20.8)	(24.7)
Participant Contributions	—	—	5.9	6.1
Medicare Subsidy	—	—	0.2	0.2
Benefit Obligation as of December 31,	$ 647.2	$ 603.1	$ 203.5	$ 205.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 593.3	$ 651.7	$ 238.4	$ 273.4
Actual Gain (Loss) on Plan Assets	87.1	(12.9)	45.3	(18.7)
Company Contributions	—	—	2.2	2.3
Participant Contributions	—	—	5.9	6.1
Benefit Payments	(43.4)	(45.5)	(20.8)	(24.7)
Fair Value of Plan Assets as of December 31,	$ 637.0	$ 593.3	$ 271.0	$ 238.4
Funded (Underfunded) Status as of December 31,	$ (10.2)	$ (9.8)	$ 67.5	$ 32.9

	Pension Plans		OPEB	
	December 31,			
APCo	2019	2018	2019	2018
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 92.0	$ 62.3
Other Current Liabilities – Accrued Short-term Benefit Liability	—	—	(2.0)	(2.1)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(10.2)	(9.8)	(22.5)	(27.3)
Funded (Underfunded) Status	$ (10.2)	$ (9.8)	$ 67.5	$ 32.9

I&M	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 567.0	$ 624.3	$ 138.3	$ 153.5
Service Cost	13.4	13.6	1.4	1.6
Interest Cost	23.8	22.1	5.8	5.4
Actuarial (Gain) Loss	49.8	(53.9)	8.1	(10.6)
Plan Amendments	—	—	(1.5)	—
Benefit Payments	(37.9)	(39.1)	(13.6)	(16.2)
Participant Contributions	—	—	4.4	4.5
Medicare Subsidy	—	—	—	0.1
Benefit Obligation as of December 31,	$ 616.1	$ 567.0	$ 142.9	$ 138.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 583.8	$ 636.7	$ 187.3	$ 211.1
Actual Gain (Loss) on Plan Assets	84.6	(13.8)	38.2	(12.1)
Company Contributions	—	—	—	—
Participant Contributions	—	—	4.4	4.5
Benefit Payments	(37.9)	(39.1)	(13.6)	(16.2)
Fair Value of Plan Assets as of December 31,	$ 630.5	$ 583.8	$ 216.3	$ 187.3
Funded Status as of December 31,	$ 14.4	$ 16.8	$ 73.4	$ 49.0

I&M	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 15.8	$ 18.0	$ 73.4	$ 49.0
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.4)	(1.2)	—	—
Funded Status	$ 14.4	$ 16.8	$ 73.4	$ 49.0

OPCo	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 453.9	$ 501.1	$ 129.5	$ 144.3
Service Cost	7.9	7.7	0.8	0.9
Interest Cost	19.1	17.7	5.5	5.1
Actuarial (Gain) Loss	40.5	(36.6)	4.9	(9.4)
Plan Amendments	—	—	(1.2)	—
Benefit Payments	(33.6)	(36.0)	(13.5)	(15.8)
Participant Contributions	—	—	4.1	4.3
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 487.8	$ 453.9	$ 130.2	$ 129.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 466.1	$ 509.1	$ 175.4	$ 198.5
Actual Gain (Loss) on Plan Assets	66.6	(7.0)	31.1	(11.6)
Participant Contributions	—	—	4.1	4.3
Benefit Payments	(33.6)	(36.0)	(13.5)	(15.8)
Fair Value of Plan Assets as of December 31,	$ 499.1	$ 466.1	$ 197.1	$ 175.4
Funded Status as of December 31,	$ 11.3	$ 12.2	$ 66.9	$ 45.9

	Pension Plans		OPEB	
	December 31,			
OPCo	2019	2018	2019	2018
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 11.7	$ 12.6	$ 66.9	$ 45.9
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(0.4)	(0.4)	—	—
Funded Status	$ 11.3	$ 12.2	$ 66.9	$ 45.9

PSO	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 253.8	$ 276.6	$ 62.3	$ 69.4
Service Cost	6.5	7.0	0.6	0.7
Interest Cost	10.6	9.9	2.6	2.5
Actuarial (Gain) Loss	16.8	(18.9)	3.8	(5.6)
Plan Amendments	—	—	(0.7)	—
Benefit Payments	(20.2)	(20.8)	(5.9)	(6.7)
Participant Contributions	—	—	2.0	2.0
Benefit Obligation as of December 31,	$ 267.5	$ 253.8	$ 64.7	$ 62.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 261.2	$ 287.8	$ 84.3	$ 95.5
Actual Gain (Loss) on Plan Assets	34.7	(5.9)	17.6	(9.2)
Company Contributions	0.5	0.1	—	2.7
Participant Contributions	—	—	2.0	2.0
Benefit Payments	(20.2)	(20.8)	(5.9)	(6.7)
Fair Value of Plan Assets as of December 31,	$ 276.2	$ 261.2	$ 98.0	$ 84.3
Funded Status as of December 31,	$ 8.7	$ 7.4	$ 33.3	$ 22.0

	Pension Plans		OPEB	
	December 31,			
PSO	2019	2018	2019	2018
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 10.6	$ 9.7	$ 33.3	$ 22.0
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.2)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.8)	(2.1)	—	—
Funded Status	$ 8.7	$ 7.4	$ 33.3	$ 22.0

SWEPCo	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 291.4	$ 314.6	$ 72.7	$ 80.3
Service Cost	8.6	9.3	0.8	0.9
Interest Cost	12.4	11.3	3.1	2.8
Actuarial (Gain) Loss	25.5	(19.2)	6.0	(5.9)
Plan Amendments	—	—	(0.8)	—
Benefit Payments	(23.7)	(24.6)	(6.6)	(7.7)
Participant Contributions	—	—	2.2	2.3
Benefit Obligation as of December 31,	$ 314.2	$ 291.4	$ 77.4	$ 72.7
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 281.0	$ 311.7	$ 98.5	$ 110.4
Actual Gain (Loss) on Plan Assets	39.5	(7.3)	23.1	(9.2)
Company Contributions	0.1	1.2	—	2.7
Participant Contributions	—	—	2.2	2.3
Benefit Payments	(23.7)	(24.6)	(6.6)	(7.7)
Fair Value of Plan Assets as of December 31,	$ 296.9	$ 281.0	$ 117.2	$ 98.5
Funded (Underfunded) Status as of December 31,	$ (17.3)	$ (10.4)	$ 39.8	$ 25.8

	Pension Plans		OPEB	
	December 31,			
SWEPCo	2019	2018	2019	2018
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 39.8	$ 25.8
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.2)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(17.2)	(10.2)	—	—
Funded (Underfunded) Status	$ (17.3)	$ (10.4)	$ 39.8	$ 25.8

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in Regulatory Assets, Deferred Income Taxes and AOCI and the items attributable to the change in these components:

AEP	**Pension Plans**		**OPEB**	
	December 31,			
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Net Actuarial Loss	$ 1,406.2	$ 1,355.2	$ 225.8	$ 419.8
Prior Service Cost (Credit)	0.2	—	(285.7)	(347.2)
Recorded as				
Regulatory Assets	$ 1,351.8	$ 1,267.9	$ (46.8)	$ 52.5
Deferred Income Taxes	11.5	18.4	(2.7)	4.2
Net of Tax AOCI	43.1	68.9	(10.4)	15.9

AEP	**Pension Plans**		**OPEB**	
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Actuarial (Gain) Loss During the Year	$ 108.6	$ 88.8	$ (171.9)	$ 120.4
Amortization of Actuarial Loss	(57.6)	(87.8)	(22.1)	(10.5)
Prior Service (Credit) Cost	0.2	—	(7.6)	—
Amortization of Prior Service Credit	—	—	69.1	69.1
Change for the Year Ended December 31,	$ 51.2	$ 1.0	$ (132.5)	$ 179.0

AEP Texas	**Pension Plans**		**OPEB**	
	December 31,			
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Net Actuarial Loss	$ 184.7	$ 182.0	$ 23.5	$ 38.0
Prior Service Credit	—	—	(24.2)	(29.5)
Recorded as				
Regulatory Assets	$ 172.2	$ 168.2	$ (0.2)	$ 8.7
Deferred Income Taxes	2.7	2.9	(0.1)	—
Net of Tax AOCI	9.8	10.9	(0.4)	(0.2)

AEP Texas	**Pension Plans**		**OPEB**	
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Actuarial (Gain) Loss During the Year	$ 7.6	$ 14.0	$ (12.7)	$ 14.9
Amortization of Actuarial Loss	(4.9)	(7.2)	(1.8)	(0.8)
Prior Service Credit	—	—	(0.6)	—
Amortization of Prior Service Credit	—	—	5.9	5.9
Change for the Year Ended December 31,	$ 2.7	$ 6.8	$ (9.2)	$ 20.0

APCo

Components	Pension Plans 2019	Pension Plans 2018	OPEB 2019	OPEB 2018
	December 31,			
	(in millions)			
Net Actuarial Loss	$ 168.3	$ 172.2	$ 28.8	$ 58.9
Prior Service Credit	—	—	(41.6)	(50.4)
Recorded as				
Regulatory Assets	$ 166.3	$ 169.6	$ (5.5)	$ 2.6
Deferred Income Taxes	0.3	0.5	(1.5)	1.2
Net of Tax AOCI	1.7	2.1	(5.8)	4.7

APCo

Components	Pension Plans 2019	Pension Plans 2018	OPEB 2019	OPEB 2018
	(in millions)			
Actuarial (Gain) Loss During the Year	$ 3.1	$ 0.3	$ (26.4)	$ 12.8
Amortization of Actuarial Loss	(7.0)	(10.6)	(3.7)	(1.9)
Prior Service Credit	—	—	(1.3)	—
Amortization of Prior Service Credit	—	—	10.1	10.0
Change for the Year Ended December 31,	$ (3.9)	$ (10.3)	$ (21.3)	$ 20.9

I&M

Components	Pension Plans 2019	Pension Plans 2018	OPEB 2019	OPEB 2018
	December 31,			
	(in millions)			
Net Actuarial Loss	$ 76.0	$ 80.6	$ 32.7	$ 54.7
Prior Service Credit	—	—	(39.0)	(47.4)
Recorded as				
Regulatory Assets	$ 73.7	$ 78.4	$ (6.2)	$ 6.5
Deferred Income Taxes	0.5	0.5	—	0.2
Net of Tax AOCI	1.8	1.7	(0.1)	0.6

I&M

Components	Pension Plans 2019	Pension Plans 2018	OPEB 2019	OPEB 2018
	(in millions)			
Actuarial (Gain) Loss During the Year	$ 2.0	$ (4.5)	$ (19.3)	$ 13.9
Amortization of Actuarial Loss	(6.6)	(9.8)	(2.7)	(1.2)
Prior Service Credit	—	—	(1.0)	—
Amortization of Prior Service Credit	—	—	9.4	9.5
Change for the Year Ended December 31,	$ (4.6)	$ (14.3)	$ (13.6)	$ 22.2

OPCo

	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
Components	(in millions)			
Net Actuarial Loss	$ 178.7	$ 180.7	$ 17.2	$ 35.5
Prior Service Credit	—	—	(28.6)	(34.7)
Recorded as				
Regulatory Assets	$ 178.7	$ 180.7	$ (11.4)	$ 0.8

OPCo

	Pension Plans		OPEB	
	2019	2018	2019	2018
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 3.3	$ (0.9)	$ (15.8)	$ 14.0
Amortization of Actuarial Loss	(5.3)	(8.0)	(2.5)	(1.1)
Prior Service Credit	—	—	(0.8)	—
Amortization of Prior Service Credit	—	—	6.9	6.9
Change for the Year Ended December 31,	$ (2.0)	$ (8.9)	$ (12.2)	$ 19.8

PSO

	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
Components	(in millions)			
Net Actuarial Loss	$ 73.0	$ 77.6	$ 18.2	$ 28.3
Prior Service Credit	—	—	(17.8)	(21.6)
Recorded as				
Regulatory Assets	$ 73.0	$ 77.6	$ 0.4	$ 6.7

PSO

	Pension Plans		OPEB	
	2019	2018	2019	2018
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (1.7)	$ 3.2	$ (8.9)	$ 9.0
Amortization of Actuarial Loss	(2.9)	(4.4)	(1.2)	(0.5)
Prior Service Credit	—	—	(0.5)	—
Amortization of Prior Service Credit	—	—	4.3	4.3
Change for the Year Ended December 31,	$ (4.6)	$ (1.2)	$ (6.3)	$ 12.8

SWEPCo	**Pension Plans**		**OPEB**	
	December 31,			
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Net Actuarial Loss	$ 97.8	$ 97.4	$ 21.1	$ 33.9
Prior Service Credit	—	—	(21.6)	(26.2)
Recorded as				
Regulatory Assets	$ 97.8	$ 97.4	$ —	$ 4.9
Deferred Income Taxes	—	—	—	0.7
Net of Tax AOCI	—	—	(0.5)	2.1

SWEPCo	**Pension Plans**		**OPEB**	
	2019	**2018**	**2019**	**2018**
Components	**(in millions)**			
Actuarial (Gain) Loss During the Year	$ 3.8	$ 5.5	$ (11.4)	$ 9.8
Amortization of Actuarial Loss	(3.4)	(5.5)	(1.4)	(0.6)
Prior Service Credit	—	—	(0.6)	—
Amortization of Prior Service Credit	—	—	5.2	5.2
Change for the Year Ended December 31,	$ 0.4	$ —	$ (8.2)	$ 14.4

Determination of Pension Expense

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

Pension and OPEB Assets

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

	Pension Plan		**OPEB**	
	December 31,			
Company	**2019**	**2018**	**2019**	**2018**
AEP Texas	8.7%	8.7%	8.3%	8.5%
APCo	12.7%	12.6%	15.2%	15.5%
I&M	12.6%	12.4%	12.1%	12.2%
OPCo	10.0%	9.9%	11.1%	11.4%
PSO	5.5%	5.6%	5.5%	5.5%
SWEPCo	5.9%	6.0%	6.6%	6.4%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 387.8	$ —	$ —	$ —	$ 387.8	7.8 %
International	609.1	—	—	—	609.1	12.1 %
Common Collective Trusts (c)	—	—	—	547.3	547.3	10.9 %
Subtotal – Equities	996.9	—	—	547.3	1,544.2	30.8 %
Fixed Income (a):						
United States Government and Agency Securities	(5.8)	1,248.6	—	—	1,242.8	24.8 %
Corporate Debt	—	1,143.7	—	—	1,143.7	22.8 %
Foreign Debt	—	211.6	—	—	211.6	4.2 %
State and Local Government	—	55.1	—	—	55.1	1.1 %
Other – Asset Backed	—	3.6	—	—	3.6	0.1 %
Subtotal – Fixed Income	(5.8)	2,662.6	—	—	2,656.8	53.0 %
Infrastructure (c)	—	—	—	85.8	85.8	1.7 %
Real Estate (c)	—	—	—	239.4	239.4	4.8 %
Alternative Investments (c)	—	—	—	448.3	448.3	8.9 %
Cash and Cash Equivalents (c)	—	24.4	—	37.2	61.6	1.2 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(20.7)	(20.7)	(0.4)%
Total	$ 991.1	$ 2,687.0	$ —	$ 1,337.3	$ 5,015.4	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 312.2	$ —	$ —	$ —	$ 312.2	17.5%
International	251.5	—	—	—	251.5	14.1%
Common Collective Trusts (b)	—	—	—	260.8	260.8	14.7%
Subtotal – Equities	563.7	—	—	260.8	824.5	46.3%
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	177.6	177.6	10.0%
United States Government and Agency Securities	(0.1)	214.4	—	—	214.3	12.0%
Corporate Debt	—	206.7	—	—	206.7	11.6%
Foreign Debt	—	35.5	—	—	35.5	2.0%
State and Local Government	58.8	14.8	—	—	73.6	4.1%
Other – Asset Backed	—	0.2	—	—	0.2	—%
Subtotal – Fixed Income	58.7	471.6	—	177.6	707.9	39.7%
Trust Owned Life Insurance:						
International Equities	—	60.2	—	—	60.2	3.4%
United States Bonds	—	151.6	—	—	151.6	8.5%
Subtotal – Trust Owned Life Insurance	—	211.8	—	—	211.8	11.9%
Cash and Cash Equivalents (b)	26.7	—	—	6.7	33.4	1.9%
Other – Pending Transactions and Accrued Income (a)	—	—	—	4.2	4.2	0.2%
Total	$ 649.1	$ 683.4	$ —	$ 449.3	$ 1,781.8	100.0%

(a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 277.3	$ —	$ —	$ —	$ 277.3	5.9%
International	384.1	—	—	—	384.1	8.2%
Options	—	18.3	—	—	18.3	0.4%
Common Collective Trusts (c)	—	—	—	370.1	370.1	7.9%
Subtotal – Equities	661.4	18.3	—	370.1	1,049.8	22.4%
Fixed Income (a):						
United States Government and Agency Securities	0.2	1,512.5	—	—	1,512.7	32.2%
Corporate Debt	—	1,082.9	—	—	1,082.9	23.0%
Foreign Debt	—	221.6	—	—	221.6	4.7%
State and Local Government	—	28.2	—	—	28.2	0.6%
Other – Asset Backed	—	7.4	—	—	7.4	0.2%
Subtotal – Fixed Income	0.2	2,852.6	—	—	2,852.8	60.7%
Infrastructure (c)	—	—	—	72.2	72.2	1.5%
Real Estate (c)	—	—	—	220.4	220.4	4.7%
Alternative Investments (c)	—	—	—	444.6	444.6	9.5%
Cash and Cash Equivalents (c)	(0.4)	36.3	—	11.9	47.8	1.0%
Other – Pending Transactions and Accrued Income (b)	—	—	—	8.3	8.3	0.2%
Total	$ 661.2	$ 2,907.2	$ —	$ 1,127.5	$ 4,695.9	100.0%

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 233.3	$ —	$ —	$ —	$ 233.3	15.2 %
International	185.9	—	—	—	185.9	12.1 %
Options	—	4.3	—	—	4.3	0.3 %
Common Collective Trusts (b)	—	—	—	226.2	226.2	14.7 %
Subtotal – Equities	419.2	4.3	—	226.2	649.7	42.3 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	163.6	163.6	10.7 %
United States Government and Agency Securities	0.2	181.5	—	—	181.7	11.8 %
Corporate Debt	—	188.6	—	—	188.6	12.3 %
Foreign Debt	—	35.0	—	—	35.0	2.3 %
State and Local Government	41.8	11.8	—	—	53.6	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.0	417.1	—	163.6	622.7	40.6 %
Trust Owned Life Insurance:						
International Equities	—	49.4	—	—	49.4	3.2 %
United States Bonds	—	154.4	—	—	154.4	10.1 %
Subtotal – Trust Owned Life Insurance	—	203.8	—	—	203.8	13.3 %
Cash and Cash Equivalents (b)	54.4	—	—	4.8	59.2	3.9 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(1.2)	(1.2)	(0.1)%
Total	$ 515.6	$ 625.2	$ —	$ 393.4	$ 1,534.2	100.0 %

(a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

Accumulated Benefit Obligation

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

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,929.0	$ 417.5	$ 627.3	$ 586.3	$ 464.2	$ 248.9	$ 291.9
Nonqualified Pension Plans	69.7	3.6	0.2	0.6	0.1	1.6	1.3
Total as of December 31, 2019	$ 4,998.7	$ 421.1	$ 627.5	$ 586.9	$ 464.3	$ 250.5	$ 293.2

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,560.7	$ 393.2	$ 588.3	$ 536.3	$ 438.3	$ 238.0	$ 271.6
Nonqualified Pension Plans	64.9	3.6	0.2	0.6	0.2	2.2	1.2
Total as of December 31, 2018	$ 4,625.6	$ 396.8	$ 588.5	$ 536.9	$ 438.5	$ 240.2	$ 272.8

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 5,236.8	$ 441.2	$ 647.2	$ 1.5	$ 0.4	$ 1.9	$ 314.2
Fair Value of Plan Assets	5,015.4	435.1	637.0	—	—	—	296.9
Underfunded Projected Benefit Obligation as of December 31, 2019	$ (221.4)	$ (6.1)	$ (10.2)	$ (1.5)	$ (0.4)	$ (1.9)	$ (17.3)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 4,810.3	$ 3.8	$ 603.1	$ 1.2	$ 0.4	$ 2.3	$ 291.4
Fair Value of Plan Assets	4,695.9	—	593.3	—	—	—	281.0
Underfunded Projected Benefit Obligation as of December 31, 2018	$ (114.4)	$ (3.8)	$ (9.8)	$ (1.2)	$ (0.4)	$ (2.3)	$ (10.4)

Accumulated Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 69.7	$ 3.6	$ 0.2	$ 0.6	$ 0.1	$ 1.6	$ 1.3
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2019	$ (69.7)	$ (3.6)	$ (0.2)	$ (0.6)	$ (0.1)	$ (1.6)	$ (1.3)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 64.9	$ 3.6	$ 0.2	$ 0.6	$ 0.2	$ 2.2	$ 1.2
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2018	$ (64.9)	$ (3.6)	$ (0.2)	$ (0.6)	$ (0.2)	$ (2.2)	$ (1.2)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded nonqualified benefits. For the qualified pension plan, additional discretionary contributions may also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant for 2020:

Company	Pension Plans	OPEB
	(in millions)	
AEP	$ 6.1	$ 3.4
AEP Texas	0.4	0.1
APCo	—	2.0
I&M	—	—
OPCo	—	—
PSO	0.1	—
SWEPCo	0.1	—

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

Pension Plans	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2020	$ 378.1	$ 37.5	$ 45.8	$ 40.1	$ 36.2	$ 20.9	$ 24.0
2021	382.8	37.3	46.0	40.5	36.1	21.3	24.7
2022	380.5	35.9	45.7	42.5	35.7	21.2	25.2
2023	383.8	36.6	46.1	42.2	35.8	22.6	25.4
2024	382.9	36.3	46.8	42.8	34.0	21.5	25.8
Years 2025 to 2029, in Total	1,800.7	162.2	217.4	211.6	161.1	98.3	119.6

OPEB Benefit Payments	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2020	$ 126.3	$ 10.0	$ 22.5	$ 15.2	$ 14.8	$ 6.8	$ 7.5
2021	124.0	10.0	21.8	15.2	14.2	6.7	7.7
2022	125.2	10.4	21.6	15.5	14.4	6.9	8.0
2023	125.0	10.6	21.2	15.5	14.3	7.0	8.2
2024	124.6	10.7	21.1	15.4	14.1	7.1	8.4
Years 2025 to 2029, in Total	592.6	50.8	97.8	72.8	65.4	33.7	40.6

OPEB Medicare Subsidy Receipts	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2020	$ 0.2	$ —	$ 0.1	$ —	$ —	$ —	$ —
2021	0.3	—	0.2	—	—	—	—
2022	0.3	—	0.2	—	—	—	—
2023	0.3	—	0.1	—	—	—	—
2024	0.3	—	0.1	—	—	—	—
Years 2025 to 2029, in Total	1.4	—	0.6	—	—	—	—

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		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
			(in millions)			
Service Cost	$ 95.5	$ 97.6	$ 96.5	$ 9.5	$ 11.6	$ 11.2
Interest Cost	204.4	187.8	203.1	50.5	47.4	59.3
Expected Return on Plan Assets	(296.0)	(290.3)	(284.8)	(93.7)	(102.2)	(101.3)
Amortization of Prior Service Cost (Credit)	—	—	1.0	(69.1)	(69.1)	(69.1)
Amortization of Net Actuarial Loss	57.6	85.2	82.8	22.1	10.5	36.7
Settlements	—	2.6	—	—	—	—
Net Periodic Benefit Cost (Credit)	61.5	82.9	98.6	(80.7)	(101.8)	(63.2)
Capitalized Portion	(38.6)	(41.1)	(39.9)	(3.8)	(4.9)	25.6
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 22.9	$ 41.8	$ 58.7	$ (84.5)	$ (106.7)	$ (37.6)

AEP Texas

	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 8.6	$ 9.2	$ 8.6	$ 0.8	$ 0.9	$ 0.9
Interest Cost	17.5	16.0	17.1	4.0	3.8	4.9
Expected Return on Plan Assets	(25.8)	(25.6)	(25.0)	(7.8)	(8.6)	(8.8)
Amortization of Prior Service Cost	—	—	—	(5.9)	(5.9)	(5.8)
Amortization of Net Actuarial Loss	4.9	7.2	7.0	1.8	0.8	3.2
Net Periodic Benefit Cost (Credit)	5.2	6.8	7.7	(7.1)	(9.0)	(5.6)
Capitalized Portion	(4.5)	(4.8)	(4.0)	(0.4)	(0.5)	2.9
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 0.7	$ 2.0	$ 3.7	$ (7.5)	$ (9.5)	$ (2.7)

APCo

	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 9.4	$ 9.3	$ 9.4	$ 1.0	$ 1.1	$ 1.1
Interest Cost	25.2	23.5	25.7	8.7	8.2	10.6
Expected Return on Plan Assets	(37.4)	(36.6)	(35.8)	(14.6)	(16.0)	(16.5)
Amortization of Prior Service Cost (Credit)	—	—	0.2	(10.1)	(10.0)	(10.1)
Amortization of Net Actuarial Loss	7.0	10.6	10.4	3.7	1.9	6.3
Net Periodic Benefit Cost (Credit)	4.2	6.8	9.9	(11.3)	(14.8)	(8.6)
Capitalized Portion	(4.0)	(3.8)	(4.0)	(0.4)	(0.5)	3.5
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 0.2	$ 3.0	$ 5.9	$ (11.7)	$ (15.3)	$ (5.1)

I&M

	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 13.4	$ 13.6	$ 14.0	$ 1.4	$ 1.6	$ 1.6
Interest Cost	23.8	22.1	24.3	5.8	5.4	6.9
Expected Return on Plan Assets	(36.8)	(35.7)	(34.6)	(11.4)	(12.3)	(12.2)
Amortization of Prior Service Cost (Credit)	—	—	0.2	(9.4)	(9.5)	(9.4)
Amortization of Net Actuarial Loss	6.6	9.8	9.7	2.7	1.2	4.4
Net Periodic Benefit Cost (Credit)	7.0	9.8	13.6	(10.9)	(13.6)	(8.7)
Capitalized Portion	(3.4)	(5.6)	(5.5)	(0.4)	(0.7)	3.5
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.6	$ 4.2	$ 8.1	$ (11.3)	$ (14.3)	$ (5.2)

OPCo

	Pension Plans			OPEB		
	Years Ended December 31,					
	2019	2018	2017	2019	2018	2017
	(in millions)					
Service Cost	$ 7.9	$ 7.7	$ 7.5	$ 0.8	$ 0.9	$ 0.9
Interest Cost	19.1	17.7	19.4	5.5	5.1	6.7
Expected Return on Plan Assets	(29.3)	(28.8)	(27.9)	(10.8)	(11.7)	(11.9)
Amortization of Prior Service Cost (Credit)	—	—	0.1	(6.9)	(6.9)	(6.9)
Amortization of Net Actuarial Loss	5.3	8.0	7.8	2.5	1.1	4.3
Net Periodic Benefit Cost (Credit)	3.0	4.6	6.9	(8.9)	(11.5)	(6.9)
Capitalized Portion	(3.7)	(3.6)	(3.3)	(0.4)	(0.4)	3.3
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (0.7)	$ 1.0	$ 3.6	$ (9.3)	$ (11.9)	$ (3.6)

PSO	**Pension Plans**			**OPEB**		
	Years Ended December 31,					
	2019	**2018**	**2017**	**2019**	**2018**	**2017**
	(in millions)					
Service Cost	$ 6.5	$ 7.0	$ 6.4	$ 0.6	$ 0.7	$ 0.7
Interest Cost	10.6	9.9	10.7	2.6	2.5	3.2
Expected Return on Plan Assets	(16.3)	(16.1)	(15.6)	(5.1)	(5.6)	(5.6)
Amortization of Prior Service Cost	—	—	—	(4.3)	(4.3)	(4.3)
Amortization of Net Actuarial Loss	2.9	4.4	4.3	1.2	0.5	2.0
Net Periodic Benefit Cost (Credit)	3.7	5.2	5.8	(5.0)	(6.2)	(4.0)
Capitalized Portion	(2.4)	(2.6)	(2.1)	(0.2)	(0.3)	1.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 1.3	$ 2.6	$ 3.7	$ (5.2)	$ (6.5)	$ (2.6)

SWEPCo	**Pension Plans**			**OPEB**		
	Years Ended December 31,					
	2019	**2018**	**2017**	**2019**	**2018**	**2017**
	(in millions)					
Service Cost	$ 8.6	$ 9.3	$ 8.7	$ 0.8	$ 0.9	$ 0.9
Interest Cost	12.4	11.3	12.3	3.1	2.8	3.6
Expected Return on Plan Assets	(17.7)	(17.3)	(17.0)	(5.9)	(6.4)	(6.3)
Amortization of Prior Service Cost (Credit)	—	—	0.1	(5.2)	(5.2)	(5.2)
Amortization of Net Actuarial Loss	3.4	5.1	4.9	1.4	0.6	2.3
Settlements	—	0.4	—	—	—	—
Net Periodic Benefit Cost (Credit)	6.7	8.8	9.0	(5.8)	(7.3)	(4.7)
Capitalized Portion	(2.9)	(3.1)	(2.7)	(0.3)	(0.3)	1.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.8	$ 5.7	$ 6.3	$ (6.1)	$ (7.6)	$ (3.3)

American Electric Power System Retirement Savings Plan

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

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

	Year Ended December 31,		
Company	**2019**	**2018**	**2017**
	(in millions)		
AEP	$ 76.4	$ 71.8	$ 74.6
AEP Texas	5.9	5.7	6.0
APCo	7.5	7.5	7.4
I&M	11.0	10.5	10.7
OPCo	6.6	6.3	6.1
PSO	4.6	4.5	5.0
SWEPCo	6.2	5.9	6.0

UMWA Benefits

Health and Welfare Benefits (Applies to AEP and APCo)

AEP provides health and welfare benefits negotiated with the UMWA for certain unionized employees, retirees and their survivors who meet eligibility requirements. APCo also provides the same UMWA health and welfare benefits for certain unionized mining retirees and their survivors who meet eligibility requirements. AEP and APCo administer the health and welfare benefits and pay them from their general assets.

Multiemployer Pension Benefits (Applies to AEP)

UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), a multiemployer plan. The UMWA pension benefits are administered by a board of trustees appointed in equal numbers by the UMWA and the Bituminous Coal Operators' Association (BCOA), an industry bargaining association. AEP makes contributions to the United Mine Workers of America 1974 Pension Plan based on provisions in its labor agreement and the plan documents. The UMWA pension plan is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. A withdrawing employer may be subject to a withdrawal liability, which is calculated based upon that employer's share of the plan's unfunded benefit obligations. If an employer fails to make required contributions or if its payments in connection with its withdrawal liability fall short of satisfying its share of the plan's unfunded benefit obligations, the remaining employers may be allocated a greater share of the remaining unfunded plan obligations. Under the Pension Protection Act of 2006 (PPA), the UMWA pension plan was in Critical and Declining Status for the plan years ending June 30, 2019 and 2018, without utilization of extended amortization provisions. As required under the PPA, the Plan adopted a Rehabilitation Plan in 2015. The Rehabilitation Plan has been updated annually, most recently in April 2019.

The amounts contributed by AEP affiliates in 2019, 2018 and 2017 were immaterial and represent less than 5% of the total contributions in the plan's latest annual report based on the plan year ended June 30, 2018. The contributions in 2019, 2018 and 2017 did not include surcharges.

Under the terms of the UMWA pension plan, contributions will be required to continue beyond the December 31, 2020 expiration of the current collective bargaining agreement between the Cook Coal Terminal (CCT) facility and the UMWA, whether or not the term of that agreement is extended or a subsequent agreement is entered, so long as both the UMWA pension plan remains in effect and an AEP affiliate continues to operate the facility covered by the current collective bargaining agreement. The contribution rate applicable would be determined in accordance with the terms of the UMWA pension plan by reference to the National Bituminous Coal Wage Agreement, subject to periodic revisions, between the UMWA and the BCOA. If the UMWA pension plan would terminate or an AEP affiliate would cease operation of the facility without arranging for a successor operator to assume its liability, the withdrawal liability obligation would be triggered.

Based upon the planned closure of CCT in 2022, AEP records a UMWA pension withdrawal liability on the balance sheet. The UMWA pension withdrawal liability is re-measured annually and is the estimated value of the company's anticipated contributions toward its proportionate share of the plan's unfunded vested liabilities. As of December 31, 2019 and 2018, the liability balance was $20 million and $15 million, respectively. AEP recovers the estimated value of its UMWA pension withdrawal liability through fuel clauses in certain regulated jurisdictions. AEP records a regulatory asset on the balance sheets when the UMWA pension withdrawal liability exceeds the cumulative billings collected and a regulatory liability on the balance sheets when the cumulative billings collected exceed the withdrawal liability. As of December 31, 2019, AEP recorded a regulatory asset on the balance sheets for $2 million and as of December 31, 2018, AEP recorded a regulatory liability on the balance sheets for $3 million. If any portion of the UMWA pension withdrawal liability is not recoverable, it could reduce future net income and cash flows and impact financial condition.

9. BUSINESS SEGMENTS

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

AEP's Reportable Segments

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by 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

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

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

The tables below present AEP's reportable segment income statement information for the years ended December 31, 2019, 2018 and 2017 and reportable segment balance sheet information as of December 31, 2019 and 2018.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
2019							
Revenues from:							
External Customers	$ 9,245.7	$ 4,319.0	$ 260.2	$ 1,721.8	$ 14.7	$ —	$ 15,561.4
Other Operating Segments	121.4	163.5	813.0	135.8	81.1	(1,314.8)	—
Total Revenues	$ 9,367.1	$ 4,482.5	$ 1,073.2	$ 1,857.6	$ 95.8	$ (1,314.8)	$ 15,561.4
Asset Impairments and Other Related Charges	$ 92.9	$ 32.5	$ —	$ 31.0	$ —	$ —	$ 156.4
Depreciation and Amortization	1,447.0	789.5	183.4	69.5	0.6	24.5 (b)	2,514.5
Interest Expense	568.3	243.3	103.3	30.0	193.7	(66.1) (b)	1,072.5
Income Tax Expense (Benefit)	(97.7)	(25.2)	136.2	(53.8)	27.6	—	(12.9)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	3.0	—	72.8	(3.8)	0.1	—	72.1
Net Income (Loss)	$ 985.6	$ 451.0	$ 520.1	$ 104.1	$ (141.0)	$ —	$ 1,919.8
Gross Property Additions	$ 2,437.4	$ 2,074.3	$ 1,458.9	$ 1,005.1	$ 14.5	$ (20.4)	$ 6,969.8
Total Property, Plant and Equipment	$ 47,323.7	$ 19,773.3	$ 10,334.0	$ 1,650.8	$ 418.4	$ (354.5) (b)	$ 79,145.7
Accumulated Depreciation and Amortization	14,580.4	3,911.2	418.9	99.0	184.5	(186.4) (b)	19,007.6
Total Property, Plant and Equipment – Net	$ 32,743.3	$ 15,862.1	$ 9,915.1	$ 1,551.8	$ 233.9	$ (168.1) (b)	$ 60,138.1
Total Assets	$ 41,228.8	$ 18,757.5	$ 11,143.5	$ 3,123.8	$ 5,440.0 (c)	$ (3,801.3) (b) (d)	$ 75,892.3
Investments in Equity Method Investees	$ 41.7	$ 2.5	$ 787.5	$ 459.5	$ 65.4	$ —	$ 1,356.6
Long-term Debt Due Within One Year:							
Affiliated	$ 20.0	$ —	$ —	$ —	$ —	$ (20.0)	$ —
Nonaffiliated	704.7	392.2	—	—	501.8 (e)	—	1,598.7
Long-term Debt:							
Affiliated	39.0	—	—	—	—	(39.0)	—
Nonaffiliated	12,162.0	6,248.1	3,593.8	—	3,122.9 (e)	—	25,126.8
Total Long-term Debt	$ 12,925.7	$ 6,640.3	$ 3,593.8	$ —	$ 3,624.7	$ (59.0)	$ 26,725.5

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	$ 9,556.7	$ 4,552.3	$ 248.6	$ 1,818.1	$ 20.0	$ —	$ 16,195.7
Other Operating Segments	88.8	100.8	555.5	122.2	75.1	(942.4)	—
Total Revenues	$ 9,645.5	$ 4,653.1	$ 804.1	$ 1,940.3	$ 95.1	$ (942.4)	$ 16,195.7
Asset Impairments and Other Related Charges	$ 3.4	$ —	$ —	$ 47.7	$ 19.5	$ —	$ 70.6
Depreciation and Amortization	1,316.2	734.1	137.8	41.0	0.4	57.1 (b)	2,286.6
Interest Expense	567.8	248.1	90.7	14.9	122.6	(59.7) (b)	984.4
Income Tax Expense (Benefit)	5.7	42.4	95.3	(49.2)	21.1	—	115.3
Equity Earnings of Unconsolidated Subsidiaries	2.7	—	68.7	0.5	1.2	—	73.1
Net Income (Loss)	$ 995.5	$ 527.4	$ 373.0	$ 134.7	$ (99.3)	$ —	$ 1,931.3
Gross Property Additions	$ 2,282.2	$ 2,162.4	$ 1,614.1	$ 289.7	$ 16.3	$ (39.2)	$ 6,325.5
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
Investments in Equity Method Investees	$ 39.6	$ 2.9	$ 750.9	$ 26.7	$ 26.1	$ —	$ 846.2
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

2017	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other(a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 9,095.1	$ 4,328.9	$ 178.4	$ 1,771.4	$ 51.1	$ —	$ 15,424.9
Other Operating Segments	96.9	90.4	588.3	103.7	69.7	(949.0)	—
Total Revenues	$ 9,192.0	$ 4,419.3	$ 766.7	$ 1,875.1	$ 120.8	$ (949.0)	$ 15,424.9
Asset Impairments and Other Related Charges	$ 33.6	$ —	$ —	$ 53.5	$ —	$ —	$ 87.1
Depreciation and Amortization	1,142.5	667.5	102.2	24.2	0.3	60.5 (b)	1,997.2
Interest Expense	540.0	244.1	72.8	18.5	63.9	(44.3) (b)	895.0
Income Tax Expense	425.6	127.2	189.8	189.7	37.4	—	969.7
Equity Earnings (Loss) of Unconsolidated Subsidiaries	$ (3.8)	$ —	$ 88.6	$ —	$ (2.4)	$ —	$ 82.4
Net Income (Loss)	$ 803.3	$ 636.4	$ 355.6	$ 166.0	$ (32.4)	$ —	$ 1,928.9
Gross Property Additions	$ 2,343.2	$ 1,558.4	$ 1,542.8	$ 328.5	$ 15.6	$ (90.4)	$ 5,698.1
Total Assets	$ 37,579.7	$ 16,060.7	$ 8,141.8	$ 2,009.8	$ 3,959.1 (c)	$ (3,022.0) (b) (d)	$ 64,729.1

(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 seven 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 years ended December 31, 2019, 2018 and 2017 and reportable segment balance sheet information as of December 31, 2019 and 2018.

2019	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
	(in millions)					
Revenues from:						
External Customers	$ 214.6	$ —		$ —		$ 214.6
Sales to AEP Affiliates	806.7	—		—		806.7
Other Revenues	0.1	—		—		0.1
Total Revenues	$ 1,021.4	$ —		$ —		$ 1,021.4
Depreciation and Amortization	$ 176.0	$ —		$ —		$ 176.0
Interest Income	1.3	123.8		(122.1)	(a)	3.0
Allowance for Equity Funds Used During Construction	84.3	—		—		84.3
Interest Expense	97.4	122.1		(122.1)	(a)	97.4
Income Tax Expense	117.1	0.3		—		117.4
Net Income	$ 438.6	$ 1.1	(b)	$ —		$ 439.7
Gross Property Additions	$ 1,419.5	$ —		$ —		$ 1,419.5
Total Transmission Property	$ 9,893.2	$ —		$ —		$ 9,893.2
Accumulated Depreciation and Amortization	402.3	—		—		402.3
Total Transmission Property - Net	$ 9,490.9	$ —		$ —		$ 9,490.9
Notes Receivable - Affiliated	$ —	$ 3,427.3		$ (3,427.3)	(c)	$ —
Total Assets	$ 9,865.0	$ 3,519.1	(d)	$ (3,493.3)	(e)	$ 9,890.8
Total Long-Term Debt	$ 3,465.0	$ 3,427.3		$ (3,465.0)	(c)	$ 3,427.3

2018	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
		(in millions)		
Revenues from:				
External Customers	$ 177.0	$ —	$ —	$ 177.0
Sales to AEP Affiliates	598.9	—	—	598.9
Other Revenues	0.2	—	—	0.2
Total Revenues	$ 776.1	$ —	$ —	$ 776.1
Depreciation and Amortization	$ 133.9	$ —	$ —	$ 133.9
Interest Income	1.3	104.6	(103.4) (a)	2.5
Allowance for Equity Funds Used During Construction	70.6	—	—	70.6
Interest Expense	83.2	103.4	(103.4) (a)	83.2
Income Tax Expense	83.9	0.2	—	84.1
Net Income	$ 314.9	$ 1.0 (b)	$ —	$ 315.9
Gross Property Additions	$ 1,570.8	$ —	$ —	$ 1,570.8
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

2017	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
		(in millions)		
Revenues from:				
External Customers	$ 138.0	$ —	$ —	$ 138.0
Sales to AEP Affiliates	568.1	—	—	568.1
Other	0.8	—	—	0.8
Total Revenues	$ 706.9	$ —	$ —	$ 706.9
Depreciation and Amortization	$ 95.7	$ —	$ —	$ 95.7
Interest Income	0.7	82.9	(82.4) (a)	1.2
Allowance for Equity Funds Used During Construction	49.0	—	—	49.0
Interest Expense	70.2	82.4	(82.4) (a)	70.2
Income Tax Expense (Benefit)	142.0	0.2	—	142.2
Net Income (Loss)	$ 270.4	$ 0.3 (b)	$ —	$ 270.7
Gross Property Additions	$ 1,522.5	$ —	$ —	$ 1,522.5
Total Assets	$ 7,086.9	$ 2,590.1 (d)	$ (2,594.9) (e)	$ 7,082.1

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

10. <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

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

The Registrants are exposed to certain market risks as major power producers and participants in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk 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
December 31, 2019

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	365.9	—	61.0	26.8	7.1	14.9	4.4
Natural Gas	MMBtus	40.7	—	—	—	—	—	11.6
Heating Oil and Gasoline	Gallons	6.9	1.8	1.1	0.6	1.4	0.7	0.9
Interest Rate	USD	$ 140.1	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 625.0	$ —	$ —	$ —	$ —	$ —	$ —

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 on Long-term Debt	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 $5 million and $18 million as of December 31, 2019 and 2018, respectively. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $39 million and $4 million as of December 31, 2019 and 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 December 31, 2019 and 2018.

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

AEP

Fair Value of Derivative Instruments
December 31, 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	$ 513.9	$ 11.5	$ 6.5	$ 531.9	$ (359.1)	$ 172.8
Long-term Risk Management Assets	290.8	11.0	12.6	314.4	(47.8)	266.6
Total Assets	804.7	22.5	19.1	846.3	(406.9)	439.4
Current Risk Management Liabilities	424.5	72.3	—	496.8	(382.5)	114.3
Long-term Risk Management Liabilities	244.5	75.7	—	320.2	(58.4)	261.8
Total Liabilities	669.0	148.0	—	817.0	(440.9)	376.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ 135.7	$ (125.5)	$ 19.1	$ 29.3	$ 34.0	$ 63.3

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
December 31, 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	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$ —	$ —	$ —

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
December 31, 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	$ 124.4	$ (85.0)	$ 39.4
Long-term Risk Management Assets	0.9	(0.8)	0.1
Total Assets	125.3	(85.8)	39.5
Current Risk Management Liabilities	86.2	(84.3)	1.9
Long-term Risk Management Liabilities	0.7	(0.7)	—
Total Liabilities	86.9	(85.0)	1.9
Total MTM Derivative Contract Net Assets (Liabilities)	$ 38.4	$ (0.8)	$ 37.6

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
December 31, 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	$ 66.9	$ (57.1)	$ 9.8
Long-term Risk Management Assets	0.5	(0.4)	0.1
Total Assets	67.4	(57.5)	9.9
Current Risk Management Liabilities	55.2	(54.7)	0.5
Long-term Risk Management Liabilities	0.4	(0.4)	—
Total Liabilities	55.6	(55.1)	0.5
Total MTM Derivative Contract Net Assets (Liabilities)	$ 11.8	$ (2.4)	$ 9.4

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
December 31, 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	7.3	—	7.3
Long-term Risk Management Liabilities	96.3	—	96.3
Total Liabilities	103.6	—	103.6
Total MTM Derivative Contract Net Liabilities	$ (103.6)	$ —	$ (103.6)

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
December 31, 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	$ 16.3	$ (0.5)	$ 15.8
Long-term Risk Management Assets	—	—	—
Total Assets	16.3	(0.5)	15.8
Current Risk Management Liabilities	0.5	(0.5)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.5	(0.5)	—
Total MTM Derivative Contract Net Assets	$ 15.8	$ —	$ 15.8

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
December 31, 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	$ 6.5	$ (0.1)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	6.5	(0.1)	6.4
Current Risk Management Liabilities	2.0	(0.1)	1.9
Long-term Risk Management Liabilities	3.1	—	3.1
Total Liabilities	5.1	(0.1)	5.0
Total MTM Derivative Contract Net Assets	$ 1.4	$ —	$ 1.4

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	$ 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 Year Ended December 31, 2019

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ 0.7	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	25.1	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	0.5	—	—	0.1
Purchased Electricity for Resale	1.9	—	1.6	0.1	—	—	—
Other Operation	(0.8)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)
Maintenance	(0.8)	(0.2)	(0.2)	(0.1)	(0.2)	(0.1)	(0.1)
Regulatory Assets (a)	(3.7)	0.7	0.3	0.3	(3.7)	1.2	(1.5)
Regulatory Liabilities (a)	102.6	—	2.4	24.5	10.1	34.6	26.6
Total Gain on Risk Management Contracts	$ 125.0	$ 0.3	$ 4.1	$ 25.2	$ 6.0	$ 35.6	$ 25.0

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ (10.4)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	38.9	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(1.9)	(8.2)	—	—	0.1
Purchased Electricity for Resale	8.6	—	7.6	0.8	—	—	—
Other Operation	1.7	0.4	0.2	0.2	0.3	0.2	0.2
Maintenance	1.9	0.4	0.4	0.2	0.4	0.2	0.2
Regulatory Assets (a)	27.9	(0.7)	(0.7)	7.1	24.9	(1.1)	(1.2)
Regulatory Liabilities (a)	222.7	(0.5)	135.5	11.6	—	37.3	11.9
Total Gain (Loss) on Risk Management Contracts	$ 291.3	$ (0.4)	$ 141.1	$ 11.7	$ 25.6	$ 36.6	$ 11.2

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2017

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ 6.1	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	42.8	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.6	5.3	—	—	0.1
Purchased Electricity for Resale	5.6	—	2.0	0.6	—	—	—
Other Operation	0.8	0.1	0.1	0.1	0.1	0.1	0.1
Maintenance	0.7	0.2	0.1	0.1	0.1	0.1	0.1
Regulatory Assets (a)	(29.4)	—	—	(7.4)	(22.0)	—	0.3
Regulatory Liabilities (a)	109.4	0.1	40.4	15.9	—	24.8	24.3
Total Gain (Loss) on Risk Management Contracts	$ 136.0	$ 0.4	$ 43.2	$ 14.6	$ (21.8)	$ 25.0	$ 24.9

(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)**	
	December 31, 2019	**December 31, 2018**	**December 31, 2019**	**December 31, 2018**
	(in millions)			
Long-term Debt (a)	$ (510.8)	$ (478.3)	$ (14.5)	$ 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:

	Twelve Months Ended December 31,		
	2019	**2018**	**2017**
	(in millions)		
Gain (Loss) on Interest Rate Contracts:			
Gain (Loss) on Fair Value Hedging Instruments (a)	$ 31.9	$ (11.3)	$ (4.8)
Gain (Loss) on Fair Value Portion of Long-term Debt (a)	(31.9)	11.3	4.8

(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 years ended 2019, 2018 and 2017, AEP applied cash flow hedging to outstanding power derivatives. During the years ended 2019, 2018 and 2017, 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 years ended 2019, 2018 and 2017, AEP applied cash flow hedging to outstanding interest rate derivatives. During the years ended 2019 and 2017, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives. During the year ended 2018, 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

	December 31, 2019		December 31, 2018	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ (103.5)	$ (11.5) (a)	$ (23.0)	$ (12.6)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	(51.7)	(2.1)	10.4	(1.1)

(a) Includes $4 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 17 for additional information.

As of December 31, 2019 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 120 months and 132 months for commodity and interest rate hedges, respectively.

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

Company	December 31, 2019		December 31, 2018	
	Interest Rate			
	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	$ (3.4)	$ (1.1)	$ (4.4)	$ (1.1)
APCo	0.9	0.9	1.8	0.9
I&M	(9.9)	(1.6)	(11.5)	(1.6)
OPCo	—	—	1.0	1.0
PSO	1.1	1.0	2.1	1.0
SWEPCo	(1.8)	(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 December 31, 2019 and 2018.

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:

	December 31, 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	$ 267.3	$ 3.7	$ 246.7
APCo	2.3	—	0.4
I&M	1.3	—	0.2
SWEPCo	5.1	—	5.1

	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

11. FAIR VALUE MEASUREMENTS

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

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:

	December 31,			
	2019		2018	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in millions)			
AEP (a)	$ 26,725.5	$ 30,172.0	$ 23,346.7	$ 24,093.9
AEP Texas	4,558.4	4,981.5	3,881.3	3,964.6
AEPTCo	3,427.3	3,868.0	2,823.0	2,782.4
APCo	4,363.8	5,253.1	4,062.6	4,473.3
I&M	3,050.2	3,453.8	3,035.4	3,070.2
OPCo	2,082.0	2,554.3	1,716.6	1,919.7
PSO	1,386.2	1,603.3	1,287.0	1,361.9
SWEPCo	2,655.6	2,927.9	2,713.4	2,670.2

(a) The fair value amount includes debt related to AEP's Equity Units issued in March 2019 and had a fair value of $871 million as of December 31, 2019. See "Equity Units" section of Note 14 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. See "Other Temporary Investments" section of Note 1 for additional information.

The following is a summary of Other Temporary Investments:

	December 31, 2019			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$ 214.7	$ —	$ —	$ 214.7
Fixed Income Securities – Mutual Funds (b)	123.2	0.1	—	123.3
Equity Securities – Mutual Funds	29.2	21.3	—	50.5
Total Other Temporary Investments	$ 367.1	$ 21.4	$ —	$ 388.5

Other Temporary Investments	December 31, 2018 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:

	Years Ended December 31, 2019	2018	2017
	(in millions)		
Proceeds from Investment Sales	$ 21.2	$ —	$ —
Purchases of Investments	45.0	3.1	14.2
Gross Realized Gains on Investment Sales	—	—	—
Gross Realized Losses on Investment Sales	0.4	—	—

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the years ended December 31, 2018 and 2017, see Note 3 - Comprehensive Income.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments:

	December 31, 2019 Fair Value	2019 Gross Unrealized Gains	2019 Other-Than-Temporary Impairments	2018 Fair Value	2018 Gross Unrealized Gains	2018 Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 15.3	$ —	$ —	$ 22.5	$ —	$ —
Fixed Income Securities:						
United States Government	1,112.5	55.5	(6.1)	996.1	26.7	(7.1)
Corporate Debt	72.4	5.3	(1.6)	52.4	1.1	(1.9)
State and Local Government	7.6	0.7	(0.2)	8.6	0.6	(0.2)
Subtotal Fixed Income Securities	1,192.5	61.5	(7.9)	1,057.1	28.4	(9.2)
Equity Securities - Domestic (a)	1,767.9	1,144.4	—	1,395.3	766.3	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,975.7	$ 1,205.9	$ (7.9)	$ 2,474.9	$ 794.7	$ (9.2)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $1.1 billion and $784 million and unrealized losses of $5 million and $18 million as of December 31, 2019 and 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:

	Years Ended December 31, 2019	2018	2017
	(in millions)		
Proceeds from Investment Sales	$ 1,473.0	$ 2,010.0	$ 2,256.3
Purchases of Investments	1,531.0	2,064.7	2,300.5
Gross Realized Gains on Investment Sales	76.5	47.5	200.7
Gross Realized Losses on Investment Sales	24.3	32.8	146.0

The base cost of fixed income securities was $1.1 billion and $1 billion as of December 31, 2019 and 2018, respectively. The base cost of equity securities was $623 million and $629 million as of December 31, 2019 and 2018, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2019 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 371.0
After 1 year through 5 years	386.2
After 5 years through 10 years	217.3
After 10 years	218.0
Total	$ 1,192.5

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 197.6	$ —	$ —	$ 17.1	$ 214.7
Fixed Income Securities – Mutual Funds	123.3	—	—	—	123.3
Equity Securities – Mutual Funds (b)	50.5	—	—	—	50.5
Total Other Temporary Investments	371.4	—	—	17.1	388.5
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	4.0	440.1	369.2	(404.5)	408.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	15.0	3.2	(6.7)	11.5
Interest Rate Hedges	—	4.6	—	—	4.6
Fair Value Hedges	—	14.5	—	—	14.5
Total Risk Management Assets	4.0	474.2	372.4	(411.2)	439.4
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	6.7	—	—	8.6	15.3
Fixed Income Securities:					
United States Government	—	1,112.5	—	—	1,112.5
Corporate Debt	—	72.4	—	—	72.4
State and Local Government	—	7.6	—	—	7.6
Subtotal Fixed Income Securities	—	1,192.5	—	—	1,192.5
Equity Securities – Domestic (b)	1,767.9	—	—	—	1,767.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,774.6	1,192.5	—	8.6	2,975.7
Total Assets	$ 2,150.0	$ 1,666.7	$ 372.4	$ (385.5)	$ 3,803.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 3.8	$ 450.0	$ 224.0	$ (438.8)	$ 239.0
Cash Flow Hedges:					
Commodity Hedges (c)	—	105.3	38.5	(6.7)	137.1
Total Risk Management Liabilities	$ 3.8	$ 555.3	$ 262.5	$ (445.5)	$ 376.1

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
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 154.7	$ —	$ —	$ —	$ 154.7

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
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 23.5	$ —	$ —	$ —	$ 23.5
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	84.6	40.5	(85.6)	39.5
Total Assets	$ 23.5	$ 84.6	$ 40.5	$ (85.6)	$ 63.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 84.0	$ 2.8	$ (84.9)	$ 1.9

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
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 59.5	$ 8.0	$ (57.6)	$ 9.9
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	6.7	—	—	8.6	15.3
Fixed Income Securities:					
United States Government	—	1,112.5	—	—	1,112.5
Corporate Debt	—	72.4	—	—	72.4
State and Local Government	—	7.6	—	—	7.6
Subtotal Fixed Income Securities	—	1,192.5	—	—	1,192.5
Equity Securities - Domestic (b)	1,767.9	—	—	—	1,767.9
Total Spent Nuclear Fuel and Decommissioning Trusts	1,774.6	1,192.5	—	8.6	2,975.7
Total Assets	$ 1,774.6	$ 1,252.0	$ 8.0	$ (49.0)	$ 2,985.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 53.4	$ 2.2	$ (55.1)	$ 0.5

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
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 103.6	$ —	$ 103.6

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
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 16.3	$ (0.5)	$ 15.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.5	$ (0.5)	$ —

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
December 31, 2019

	Level 1		Level 2		Level 3		Other		Total	
Assets:					(in millions)					
Risk Management Assets										
Risk Management Commodity Contracts (c) (g)	$	—	$	—	$	6.5	$	(0.1)	$	6.4
Liabilities:										
Risk Management Liabilities										
Risk Management Commodity Contracts (c) (g)	$	—	$	—	$	5.1	$	(0.1)	$	5.0

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 December 31, 2019 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 2 matures $(7) million in 2020 and $(3) million in periods 2021-2023; Level 3 matures $96 million in 2020, $36 million in periods 2021-2023, $25 million in periods 2024-2025 and $(12) million in periods 2026-2032. 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.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 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)	15.8	(13.9)	4.7	(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)	(0.1)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(15.1)	—	—	—	—	—
Settlements	(117.6)	(42.5)	(13.0)	6.6	(23.0)	(9.6)
Transfers into Level 3 (d) (e)	(0.6)	(0.5)	(0.3)	—	—	—
Transfers out of Level 3 (e)	35.6	(0.7)	(0.4)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	60.7	37.5	5.9	(9.9)	15.8	2.7
Balance as of December 31, 2019	$ 109.9	$ 37.7	$ 5.8	$ (103.6)	$ 15.8	$ 1.4

Year Ended December 31, 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)	148.9	104.1	14.2	1.8	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)	9.8	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	15.7	—	—	—	—	—
Settlements	(214.0)	(127.9)	(21.3)	4.6	(24.3)	(2.1)
Transfers into Level 3 (d) (e)	15.8	—	—	—	—	—
Transfers out of Level 3 (e)	(1.6)	—	(0.3)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	116.3	56.9	8.7	26.6	9.5	3.3
Balance as of December 31, 2018	$ 131.2	$ 57.8	$ 8.9	$ (99.4)	$ 9.5	$ 2.3

Year Ended December 31, 2017	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2016	$ 2.5	$ 1.4	$ 2.8	$ (119.0)	$ 0.7	$ 0.7
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	37.3	17.2	4.0	(1.4)	3.1	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	33.6	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(18.8)	—	—	—	—	—
Settlements	(50.6)	(18.9)	(7.1)	7.4	(3.8)	(6.8)
Transfers into Level 3 (d) (e)	16.2	—	—	—	—	—
Transfers out of Level 3 (e)	(10.1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	30.2	25.0	7.9	(19.4)	6.2	6.0
Balance as of December 31, 2017	$ 40.3	$ 24.7	$ 7.6	$ (132.4)	$ 6.2	$ 5.9

(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) Included in cash flow hedges on the statements of comprehensive income.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory

assets/liabilities or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
December 31, 2019

AEP

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 296.7	$ 249.3	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 177.30	$ 31.31
Natural Gas Contracts	—	4.9	Discounted Cash Flow	Forward Market Price (b)	1.89	2.51	2.19
FTRs	75.7	8.3	Discounted Cash Flow	Forward Market Price (a)	(8.52)	9.34	0.42
Total	$ 372.4	$ 262.5					

December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input	Low	High	Weighted Average (c)
	(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
December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 5.7	$ 2.6	Discounted Cash Flow	Forward Market Price	$ 12.70	$ 41.20	$ 25.92
FTRs	34.8	0.2	Discounted Cash Flow	Forward Market Price	(0.14)	7.08	1.70
Total	$ 40.5	$ 2.8					

December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(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
December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 3.4	$ 1.5	Discounted Cash Flow	Forward Market Price	$ 12.70	$ 41.20	$ 25.92
FTRs	4.6	0.7	Discounted Cash Flow	Forward Market Price	(0.75)	4.07	0.74
Total	$ 8.0	$ 2.2					

December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(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
December 31, 2019

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 103.6	Discounted Cash Flow	Forward Market Price	$ 29.23	$ 61.43	$ 42.46

December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 99.4	Discounted Cash Flow	Forward Market Price	$ 26.29	$ 62.74	$ 42.50

PSO

Significant Unobservable Inputs
December 31, 2019

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 16.3	$ 0.5	Discounted Cash Flow	Forward Market Price	$ (8.52)	$ 0.85	$ (2.31)

December 31, 2018

	Fair Value		Valuation	Significant	Input/Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 10.8	$ 1.3	Discounted Cash Flow	Forward Market Price	$ (11.68)	$ 10.30	$ (1.40)

SWEPCo

Significant Unobservable Inputs
December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ —	$ 4.9	Discounted Cash Flow	Forward Market Price (b)	$ 1.89	$ 2.51	$ 2.18
FTRs	6.5	0.2	Discounted Cash Flow	Forward Market Price (a)	(8.52)	0.85	(2.31)
Total	$ 6.5	$ 5.1					

December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(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.
(c) The weighted average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty 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 December 31, 2019 and 2018:

Uncertainty 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)

12. INCOME TAXES

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

Income Tax Expense (Benefit)

The details of the Registrants' Income Tax Expense (Benefit) as reported are as follows:

Year Ended December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Federal:								
Current	$ (7.4)	$ (31.8)	$ 23.7	$ 36.7	$ 48.1	$ (10.0)	$ 25.5	$ 6.9
Deferred	(77.1)	(23.5)	71.7	(125.6)	(53.5)	40.6	(23.6)	(8.6)
Deferred Investment Tax Credits	5.5	(1.2)	—	(0.5)	(3.6)	—	(2.4)	(1.4)
Total Federal	(79.0)	(56.5)	95.4	(89.4)	(9.0)	30.6	(0.5)	(3.1)
State and Local:								
Current	4.4	2.9	2.4	12.0	(2.4)	1.1	0.2	0.8
Deferred	59.3	—	19.6	(0.6)	0.8	3.2	5.4	(2.4)
Deferred Investment Tax Credits	2.4	—	—	—	—	—	2.4	—
Total State and Local	66.1	2.9	22.0	11.4	(1.6)	4.3	8.0	(1.6)
Income Tax Expense (Benefit)	$ (12.9)	$ (53.6)	$ 117.4	$ (78.0)	$ (10.6)	$ 34.9	$ 7.5	$ (4.7)

Year Ended December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Federal:								
Current	$ (31.7)	$ 37.0	$ (14.2)	$ (31.9)	$ 60.9	$ 55.6	$ 35.6	$ 18.3
Deferred	112.8	(16.4)	82.3	(24.6)	(44.1)	(36.9)	(34.7)	(0.5)
Deferred Investment Tax Credits	9.2	(1.5)	—	0.1	(4.7)	—	(2.0)	(1.4)
Total Federal	90.3	19.1	68.1	(56.4)	12.1	18.7	(1.1)	16.4
State and Local:								
Current	30.8	1.8	(0.6)	3.7	15.8	4.6	(0.2)	2.3
Deferred	(8.5)	(0.1)	16.6	7.8	1.2	0.7	3.6	1.7
Deferred Investment Tax Credits	2.7	—	—	—	—	—	2.7	—
Total State and Local	25.0	1.7	16.0	11.5	17.0	5.3	6.1	4.0
Income Tax Expense (Benefit)	$ 115.3	$ 20.8	$ 84.1	$ (44.9)	$ 29.1	$ 24.0	$ 5.0	$ 20.4

Year Ended December 31, 2017	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Federal:								
Current	$ (4.0)	$ (85.7)	$ (130.4)	$ 15.3	$ (106.5)	$ 11.2	$ (77.1)	$ (30.1)
Deferred	856.6	63.3	254.8	166.9	202.1	141.3	122.7	84.8
Deferred Investment Tax Credits	48.6	(1.6)	—	(0.1)	(4.7)	—	(1.6)	(1.4)
Total Federal	901.2	(24.0)	124.4	182.1	90.9	152.5	44.0	53.3
State and Local:								
Current	16.0	0.6	1.1	(1.4)	(8.1)	0.2	(0.2)	(0.9)
Deferred	44.9	—	16.7	4.6	(1.4)	6.6	2.0	(4.3)
Deferred Investment Tax Credits	7.6	—	—	—	—	—	4.3	—
Total State and Local	68.5	0.6	17.8	3.2	(9.5)	6.8	6.1	(5.2)
Income Tax Expense (Benefit)	$ 969.7	$ (23.4)	$ 142.2	$ 185.3	$ 81.4	$ 159.3	$ 50.1	$ 48.1

The following are reconciliations for the Registrants between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

AEP

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net Income	$ 1,919.8	$ 1,931.3	$ 1,928.9
Less: Equity Earnings – Dolet Hills	(3.0)	(2.7)	—
Income Tax Expense (Benefit)	(12.9)	115.3	969.7
Pretax Income	$ 1,903.9	$ 2,043.9	$ 2,898.6
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 399.8	$ 429.2	$ 1,014.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	23.1	24.4	60.2
Investment Tax Credit Amortization	(13.0)	(20.2)	(18.8)
Production Tax Credits	(59.0)	(10.3)	—
State and Local Income Taxes, Net	52.2	19.7	54.7
Removal Costs	(20.7)	(19.8)	(32.7)
AFUDC	(37.1)	(29.4)	(37.4)
Valuation Allowance	—	—	(1.8)
Tax Reform Adjustments	—	(10.9)	(26.7)
Tax Adjustments	—	—	(35.8)
Tax Reform Excess ADIT Reversal	(353.2)	(257.2)	—
Other	(5.0)	(10.2)	(6.5)
Income Tax Expense (Benefit)	$ (12.9)	$ 115.3	$ 969.7
Effective Income Tax Rate	(0.7) %	5.6 %	33.5 %

AEP Texas

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net Income	$ 178.3	$ 211.3	$ 310.5
Income Tax Expense (Benefit)	(53.6)	20.8	(23.4)
Pretax Income	$ 124.7	$ 232.1	$ 287.1
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 26.2	$ 48.7	$ 100.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.0	1.4	(0.5)
Investment Tax Credit Amortization	(1.2)	(2.3)	(1.5)
State and Local Income Taxes, Net	2.3	1.3	0.4
AFUDC	(3.2)	(4.2)	(3.9)
Parent Company Loss Benefit	(4.6)	(3.1)	—
Tax Reform Adjustments	—	(11.0)	(117.4)
Tax Adjustments	—	—	(4.2)
Tax Reform Excess ADIT Reversal	(73.4)	(11.8)	—
Other	(0.7)	1.8	3.2
Income Tax Expense (Benefit)	$ (53.6)	$ 20.8	$ (23.4)
Effective Income Tax Rate	(43.0) %	9.0 %	(8.2) %

AEPTCo

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net Income	$ 439.7	$ 315.9	$ 270.7
Income Tax Expense	117.4	84.1	142.2
Pretax Income	$ 557.1	$ 400.0	$ 412.9
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 117.0	$ 84.0	$ 144.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
AFUDC	(17.7)	(14.1)	(17.0)
State and Local Income Taxes, Net	17.4	12.6	13.1
Tax Reform Adjustments	—	—	0.6
Other	0.7	1.6	1.0
Income Tax Expense	$ 117.4	$ 84.1	$ 142.2
Effective Income Tax Rate	21.1 %	21.0 %	34.4 %

APCo

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net Income	$ 306.3	$ 367.8	$ 331.3
Income Tax Expense (Benefit)	(78.0)	(44.9)	185.3
Pretax Income	$ 228.3	$ 322.9	$ 516.6
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 47.9	$ 67.8	$ 180.8
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	11.7	8.5	18.0
State and Local Income Taxes, Net	9.0	9.1	3.5
Removal Costs	(6.1)	(9.6)	(12.4)
AFUDC	(5.2)	(4.3)	(5.0)
Parent Company Loss Benefit	(3.8)	(3.4)	(0.2)
Tax Reform Adjustments	—	0.1	4.3
Tax Reform Excess ADIT Reversal	(130.4)	(108.5)	—
Other	(1.1)	(4.6)	(3.7)
Income Tax Expense (Benefit)	$ (78.0)	$ (44.9)	$ 185.3
Effective Income Tax Rate	(34.2) %	(13.9) %	35.9 %

I&M

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net Income	$ 269.4	$ 261.3	$ 186.7
Income Tax Expense (Benefit)	(10.6)	29.1	81.4
Pretax Income	$ 258.8	$ 290.4	$ 268.1
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 54.3	$ 61.0	$ 93.8
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	6.3	(0.7)	11.4
Investment Tax Credit Amortization	(3.6)	(4.7)	(4.7)
State and Local Income Taxes, Net	(1.2)	13.4	(1.0)
Removal Costs	(11.5)	(8.0)	(13.3)
AFUDC	(4.1)	(2.5)	(5.6)
Parent Company Loss Benefit	(4.8)	(2.3)	—
Tax Adjustments	—	—	2.7
Tax Reform Adjustments	—	—	(2.9)
Tax Reform Excess ADIT Reversal	(42.5)	(25.8)	—
Other	(3.5)	(1.3)	1.0
Income Tax Expense (Benefit)	$ (10.6)	$ 29.1	$ 81.4
Effective Income Tax Rate	(4.1) %	10.0 %	30.4 %

OPCo

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net Income	$ 297.1	$ 325.5	$ 323.9
Income Tax Expense	34.9	24.0	159.3
Pretax Income	$ 332.0	$ 349.5	$ 483.2
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 69.7	$ 73.4	$ 169.1
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	(1.7)	2.6	7.6
State and Local Income Taxes, Net	3.4	4.2	4.4
AFUDC	(3.8)	(2.1)	(2.2)
Tax Reform Adjustments	—	—	(14.4)
Tax Reform Excess ADIT Reversal	(27.3)	(51.0)	—
Parent Company Loss Benefit	(4.9)	(5.5)	(0.2)
Other	(0.5)	2.4	(5.0)
Income Tax Expense	$ 34.9	$ 24.0	$ 159.3
Effective Income Tax Rate	10.5 %	6.9 %	33.0 %

PSO

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net Income	$ 137.6	$ 83.2	$ 72.0
Income Tax Expense	7.5	5.0	50.1
Pretax Income	$ 145.1	$ 88.2	$ 122.1
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 30.5	$ 18.5	$ 42.7
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	0.5	1.0	0.3
Investment Tax Credit Amortization	(0.5)	(1.7)	(1.6)
Parent Company Loss Benefit	(2.5)	(1.4)	—
State and Local Income Taxes, Net	6.3	4.8	4.0
Tax Reform Adjustments	—	—	2.8
Tax Reform Excess ADIT Reversal	(24.5)	(15.5)	—
Other	(2.3)	(0.7)	1.9
Income Tax Expense	$ 7.5	$ 5.0	$ 50.1
Effective Income Tax Rate	5.2 %	5.7 %	41.0 %

SWEPCo

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net Income	$ 162.2	$ 152.2	$ 137.5
Less: Equity Earnings – Dolet Hills	(3.0)	(2.7)	—
Income Tax Expense (Benefit)	(4.7)	20.4	48.1
Pretax Income	$ 154.5	$ 169.9	$ 185.6
Income Taxes on Pretax Income at Statutory Rate (21%, 21% and 35% in 2019, 2018 and 2017, Respectively)	$ 32.4	$ 35.7	$ 65.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.9	3.4	1.9
Depletion	(3.6)	(3.2)	(5.7)
State and Local Income Taxes, Net	(1.3)	3.2	(2.3)
AFUDC	(1.4)	(1.3)	(0.9)
Tax Adjustments	—	—	(9.9)
Tax Reform Adjustments	—	—	(0.4)
Tax Reform Excess ADIT Reversal	(29.9)	(16.0)	—
Other	(2.8)	(1.4)	0.4
Income Tax Expense (Benefit)	$ (4.7)	$ 20.4	$ 48.1
Effective Income Tax Rate	(3.0) %	12.0 %	25.9 %

Net Deferred Tax Liability

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant:

AEP	**December 31,**	
	2019	**2018**
	(in millions)	
Deferred Tax Assets	$ 3,246.1	$ 2,750.8
Deferred Tax Liabilities	(10,834.3)	(9,837.3)
Net Deferred Tax Liabilities	$ (7,588.2)	$ (7,086.5)
Property Related Temporary Differences	$ (6,602.9)	$ (6,224.8)
Amounts Due to Customers for Future Income Taxes	1,173.5	1,329.7
Deferred State Income Taxes	(1,112.4)	(1,072.5)
Securitized Assets	(178.7)	(186.6)
Regulatory Assets	(371.1)	(454.1)
Accrued Nuclear Decommissioning	(557.4)	(453.7)
Net Operating Loss Carryforward	77.6	78.3
Tax Credit Carryforward	247.2	113.7
Operating Lease Liability	182.6	—
Investment in Partnership	(446.6)	(300.5)
All Other, Net	—	84.0
Net Deferred Tax Liabilities	$ (7,588.2)	$ (7,086.5)

AEP Texas	**December 31,**	
	2019	**2018**
	(in millions)	
Deferred Tax Assets	$ 220.0	$ 208.1
Deferred Tax Liabilities	(1,185.4)	(1,121.2)
Net Deferred Tax Liabilities	$ (965.4)	$ (913.1)
Property Related Temporary Differences	$ (973.5)	$ (836.3)
Amounts Due to Customers for Future Income Taxes	126.7	141.2
Deferred State Income Taxes	(27.5)	(27.7)
Regulatory Assets	(51.2)	(53.9)
Securitized Transition Assets	(124.3)	(134.7)
Deferred Revenues	19.9	4.6
Operating Lease Liability	17.2	—
All Other, Net	47.3	(6.3)
Net Deferred Tax Liabilities	$ (965.4)	$ (913.1)

AEPTCo

	December 31,	
	2019	2018
	(in millions)	
Deferred Tax Assets	$ 162.9	$ 142.9
Deferred Tax Liabilities	(980.7)	(847.3)
Net Deferred Tax Liabilities	$ (817.8)	$ (704.4)
Property Related Temporary Differences	$ (847.1)	$ (755.0)
Amounts Due to Customers for Future Income Taxes	119.9	121.3
Deferred State Income Taxes	(86.1)	(71.6)
Net Operating Loss Carryforward	12.3	13.4
All Other, Net	(16.8)	(12.5)
Net Deferred Tax Liabilities	$ (817.8)	$ (704.4)

APCo

	December 31,	
	2019	2018
	(in millions)	
Deferred Tax Assets	$ 486.2	$ 475.2
Deferred Tax Liabilities	(2,167.0)	(2,101.0)
Net Deferred Tax Liabilities	$ (1,680.8)	$ (1,625.8)
Property Related Temporary Differences	$ (1,420.0)	$ (1,393.6)
Amounts Due to Customers for Future Income Taxes	222.8	268.0
Deferred State Income Taxes	(320.9)	(324.1)
Regulatory Assets	(71.0)	(73.8)
Securitized Assets	(49.3)	(54.3)
Operating Lease Liability	16.5	—
All Other, Net	(58.9)	(48.0)
Net Deferred Tax Liabilities	$ (1,680.8)	$ (1,625.8)

I&M

	December 31,	
	2019	2018
	(in millions)	
Deferred Tax Assets	$ 970.5	$ 771.6
Deferred Tax Liabilities	(1,950.2)	(1,719.6)
Net Deferred Tax Liabilities	$ (979.7)	$ (948.0)
Property Related Temporary Differences	$ (430.7)	$ (445.0)
Amounts Due to Customers for Future Income Taxes	169.6	186.2
Deferred State Income Taxes	(194.4)	(183.9)
Accrued Nuclear Decommissioning	(557.4)	(453.7)
Regulatory Assets	(26.9)	(31.9)
Net Operating Loss Carryforward	—	0.2
Operating Lease Liability	61.9	—
All Other, Net	(1.8)	(19.9)
Net Deferred Tax Liabilities	$ (979.7)	$ (948.0)

OPCo

	December 31,	
	2019	2018
	(in millions)	
Deferred Tax Assets	$ 202.3	$ 209.0
Deferred Tax Liabilities	(1,051.6)	(972.3)
Net Deferred Tax Liabilities	$ (849.3)	$ (763.3)
Property Related Temporary Differences	$ (890.8)	$ (826.9)
Amounts Due to Customers for Future Income Taxes	130.2	137.0
Deferred State Income Taxes	(35.5)	(32.9)
Regulatory Assets	(48.0)	(55.0)
Operating Lease Liability	18.3	—
All Other, Net	(23.5)	14.5
Net Deferred Tax Liabilities	$ (849.3)	$ (763.3)

PSO

	December 31,	
	2019	2018
	(in millions)	
Deferred Tax Assets	$ 257.4	$ 229.6
Deferred Tax Liabilities	(885.7)	(837.4)
Net Deferred Tax Liabilities	$ (628.3)	$ (607.8)
Property Related Temporary Differences	$ (627.6)	$ (609.4)
Amounts Due to Customers for Future Income Taxes	127.2	138.9
Deferred State Income Taxes	(100.4)	(135.6)
Regulatory Assets	(44.6)	(32.3)
Net Operating Loss Carryforward	10.2	16.4
All Other, Net	6.9	14.2
Net Deferred Tax Liabilities	$ (628.3)	$ (607.8)

SWEPCo

	December 31,	
	2019	2018
	(in millions)	
Deferred Tax Assets	$ 359.6	$ 317.4
Deferred Tax Liabilities	(1,300.5)	(1,220.2)
Net Deferred Tax Liabilities	$ (940.9)	$ (902.8)
Property Related Temporary Differences	$ (947.6)	$ (913.3)
Amounts Due to Customers for Future Income Taxes	169.8	183.4
Deferred State Income Taxes	(200.3)	(193.6)
Regulatory Assets	(30.2)	(30.8)
Net Operating Loss Carryforward	38.2	36.2
All Other, Net	29.2	15.3
Net Deferred Tax Liabilities	$ (940.9)	$ (902.8)

AEP System Tax Allocation Agreement

AEP and subsidiaries join in the filing of a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses ("Parent Company Loss Benefit") to the AEP System companies giving rise to such losses in determining their current tax expense. The consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss, the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

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 2015. During the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 and 2015 federal returns and as such the IRS may examine only the amended items on the 2014 and 2015 federal returns.

Net Income Tax Operating Loss Carryforward

As of December 31, 2019, AEP has no federal net income tax operating loss carryforward. AEP, AEPTCo, I&M, PSO and SWEPCo have state net income tax operating loss carryforwards as indicated in the table below:

Company	State/Municipality	State Net Income Tax Operating Loss Carryforward		Years of Expiration		
		(in millions)				
AEP	Arkansas	$	102.5	2020	-	2024
AEP	Kentucky		144.9	2030	-	2037
AEP	Louisiana		541.0	2025	-	2039
AEP	Oklahoma		544.1	2034	-	2037
AEP	Tennessee		29.0	2028	-	2034
AEP	Virginia		22.6	2030	-	2037
AEP	West Virginia		16.1	2029	-	2037
AEP	Ohio Municipal		414.1	2020	-	2024
AEPTCo	Oklahoma		269.4	2034	-	2037
AEPTCo	Ohio Municipal		37.3	2020	-	2023
I&M	West Virginia		2.0	2031	-	2037
PSO	Oklahoma		240.5	2034	-	2037
SWEPCo	Arkansas		101.7	2021	-	2024
SWEPCo	Louisiana		528.1	2032	-	2037

As of December 31, 2019, AEP has recorded a valuation allowance of $6 million, against certain state and municipal net income tax operating loss carryforwards since future taxable income is not expected to be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires. Management anticipates future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires for each state.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2017, 2012 and 2011 resulted in unused federal and state income tax credits. As of December 31, 2019, the Registrants have federal tax credit carryforwards and AEP and PSO have state tax credit carryforwards as indicated in the table below. If these credits are not utilized, federal general business tax credits will expire in the years 2031 through 2039.

Company	Total Federal Tax Credit Carryforward	Federal Tax Credit Carryforward Subject to Expiration	Total State Tax Credit Carryforward	State Tax Credit Carryforward Subject to Expiration
	(in millions)			
AEP	$ 247.2	$ 239.6	$ 36.7	$ —
AEP Texas	1.4	1.3	—	—
AEPTCo	0.2	0.1	—	—
APCo	4.9	2.3	—	—
I&M	13.9	13.7	—	—
OPCo	5.1	1.7	—	—
PSO	1.1	1.1	36.7	—
SWEPCo	1.9	1.8	—	—

The Registrants anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Valuation Allowance

AEP assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective evidence evaluated includes whether AEP has a history of recognizing income of the character which can be offset by loss carryforwards. Other objective negative evidence evaluated is the impact recently enacted federal tax legislation will have on future taxable income and on AEP's ability to benefit from the carryforward of charitable contribution deductions.

Valuation allowance activity for the years ended December 31, 2019, 2018 and 2017 was immaterial.

Uncertain Tax Positions

The reconciliations of the beginning and ending amounts of unrecognized tax benefits are as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Balance as of January 1, 2019	$ 14.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)
Increase – Tax Positions Taken During a Prior Period	8.8	1.5	—	—	—	1.6	—	0.8
Decrease – Tax Positions Taken During a Prior Period	(2.1)	(0.7)	—	—	(0.7)	—	—	—
Increase – Tax Positions Taken During the Current Year	2.8	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	—	—	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2019	$ 24.1	$ —	$ —	$ —	$ 2.5	$ 8.5	$ —	$ —

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Balance as of January 1, 2018	$ 86.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)
Increase – Tax Positions Taken During a Prior Period	0.1	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During a Prior Period	—	—	—	—	—	—	—	—
Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	(71.0)	—	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	(1.1)	—	—	—	—	—	—	—
Balance as of December 31, 2018	$ 14.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Balance as of January 1, 2017	$ 98.8	$ 6.5	$ —	$ —	$ 3.8	$ 6.9	$ 0.1	$ 1.3
Increase – Tax Positions Taken During a Prior Period	4.5	2.0	—	—	0.2	—	0.1	1.7
Decrease – Tax Positions Taken During a Prior Period	(28.0)	(12.3)	—	—	(0.5)	—	(0.9)	(5.4)
Increase – Tax Positions Taken During the Current Year	3.4	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	7.9	3.0	—	—	(0.3)	—	0.7	1.6
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2017	$ 86.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant was as follows:

Company	2019	2018	2017
		(in millions)	
AEP	$ 20.3	$ 11.6	$ 10.5
AEP Texas	—	(0.7)	(0.5)
AEPTCo	—	—	—
APCo	—	—	—
I&M	2.0	2.6	2.1
OPCo	6.7	5.4	4.5
PSO	—	—	—
SWEPCo	—	(0.6)	(0.5)

Federal Tax Reform and Legislation

In December 2017, Tax Reform legislation was signed into law. Tax Reform included significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%.

The IRS has issued new regulations that provide guidance regarding the additional first-year depreciation deduction under Section 168(k). The proposed regulations reflect changes as a result of Tax Reform and affect taxpayers with qualified depreciable property acquired and placed in-service after September 27, 2017. Generally, AEP's regulated utilities will not be eligible for any bonus depreciation for property acquired and placed in-service after December 31, 2017 and AEP's competitive businesses will be eligible for 100% expensing.

During the fourth quarter of 2018, the IRS proposed new regulations that reflect changes as a result of Tax Reform concerning potential limitations on the deduction of business interest expense. These regulations require an allocation of net interest expense between regulated and competitive businesses within the consolidated tax return. This allocation is based upon net tax basis, and the proposed regulations provide a de minimis test under which all interest is deductible if less than 10% is allocable to the competitive businesses. Management continues to review and evaluate the proposed regulations and at this time expect to be able to deduct materially all business interest expense under this de minimis provision.

State Tax Legislation

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 Section 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 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.

13. 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. AEP has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. 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.

Operating lease rentals and finance lease amortization costs are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Effective in 2019, interest on finance lease liabilities is generally charged to Interest Expense. Finance lease interest for periods prior to 2019 were charged to Other Operation and Maintenance expense. Lease costs associated with capital projects are included in Property, Plant and Equipment on the balance sheets. 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:

Year Ended December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 286.0	$ 16.5	$ 2.5	$ 19.5	$ 93.1	$ 18.0	$ 6.8	$ 8.0
Finance Lease Cost:								
Amortization of Right-of-Use Assets	70.8	5.1	0.1	6.7	5.7	3.5	3.1	11.0
Interest on Lease Liabilities	16.4	1.4	—	2.9	2.9	0.7	0.6	2.9
Total Lease Rental Costs (a)	$ 373.2	$ 23.0	$ 2.6	$ 29.1	$ 101.7	$ 22.2	$ 10.5	$ 21.9

Year Ended December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 245.0	$ 13.6	$ 2.7	$ 18.2	$ 89.2	$ 10.7	$ 5.7	$ 6.5
Finance Lease Cost:								
Amortization of Right-of-Use Assets	62.4	4.8	0.1	7.0	6.6	3.9	3.2	11.2
Interest on Lease Liabilities	16.4	1.2	—	3.0	3.3	0.5	0.4	3.2
Total Lease Rental Costs	$ 323.8	$ 19.6	$ 2.8	$ 28.2	$ 99.1	$ 15.1	$ 9.3	$ 20.9

Year Ended December 31, 2017	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 231.3	$ 10.5	$ 1.7	$ 17.5	$ 88.4	$ 8.2	$ 4.4	$ 5.3
Finance Lease Cost:								
Amortization of Right-of-Use Assets	66.3	4.0	—	6.9	11.1	4.1	4.0	11.2
Interest on Lease Liabilities	16.7	0.8	—	3.7	3.2	0.5	0.6	3.6
Total Lease Rental Costs	$ 314.3	$ 15.3	$ 1.7	$ 28.1	$ 102.7	$ 12.8	$ 9.0	$ 20.1

(a) Excludes variable and short-term lease costs, which were immaterial for the twelve months ended December 31, 2019.

Supplemental information related to leases are shown in the tables below:

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	5.23	6.93	2.25	6.28	3.91	7.94	7.07	6.64
Finance Leases	5.85	6.69	0.25	6.12	6.55	6.49	6.23	5.16
Weighted-Average Discount Rate:								
Operating Leases	3.60%	3.77%	3.14%	3.64%	3.45%	3.76%	3.64%	3.76%
Finance Leases	5.98%	4.62%	9.33%	8.08%	8.47%	4.54%	4.62%	5.01%

Year Ended December 31,2019	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	$ 284.7	$ 15.3	$ 2.4	$ 19.0	$ 94.3	$ 18.0	$ 6.7	$ 7.9
Operating Cash Flows Used for Finance Leases	16.4	1.4	—	2.9	3.1	0.7	0.6	3.0
Financing Cash Flows Used for Finance Leases	70.7	5.1	—	6.7	5.7	3.5	3.1	11.0
Non-cash Acquisitions Under Operating Leases	$ 125.0	$ 13.8	$ 0.6	$ 10.2	$ 18.7	$ 35.4	$ 8.2	$ 11.4

The following tables show property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on the 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 balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 131.6	$ —	$ —	$ 39.9	$ 28.8	$ —	$ 0.6	$ 34.1
Other Property, Plant and Equipment	323.0	45.9	0.2	18.9	39.3	27.3	21.6	51.6
Total Property, Plant and Equipment	454.6	45.9	0.2	58.8	68.1	27.3	22.2	85.7
Accumulated Amortization	151.5	11.8	0.2	17.0	23.0	7.2	7.1	28.4
Net Property, Plant and Equipment Under Finance Leases	$ 303.1	$ 34.1	$ —	$ 41.8	$ 45.1	$ 20.1	$ 15.1	$ 57.3
Obligations Under Finance Leases:								
Noncurrent Liability	$ 249.2	$ 28.2	$ —	$ 35.0	$ 38.8	$ 16.2	$ 11.9	$ 47.1
Liability Due Within One Year	57.6	5.9	—	6.8	6.3	3.9	3.2	10.5
Total Obligations Under Finance Leases	$ 306.8	$ 34.1	$ —	$ 41.8	$ 45.1	$ 20.1	$ 15.1	$ 57.6

December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 131.3	$ —	$ —	$ 38.7	$ 27.0	$ —	$ 2.6	$ 34.3
Other Property, Plant and Equipment	373.9	38.8	0.2	17.3	33.3	20.4	17.6	119.8
Total Property, Plant and Equipment	505.2	38.8	0.2	56.0	60.3	20.4	20.2	154.1
Accumulated Amortization	226.4	10.3	0.1	16.2	21.6	8.3	7.9	99.9
Net Property, Plant and Equipment Under Finance Leases	$ 278.8	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 54.2
Obligations Under Finance Leases:								
Noncurrent Liability	$ 233.5	$ 24.0	$ —	$ 33.7	$ 33.4	$ 9.2	$ 9.5	$ 50.6

Liability Due Within One Year	55.5	55.5	4.5	0.1	6.1	5.3	2.9	2.8	10.2
Total Obligations Under Finance Leases	$ 289.0		$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 60.8

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Operating Lease Assets	$ 957.4	$ 81.8	$ 3.8	$ 78.5	$ 294.9	$ 88.0	$ 36.8	$ 40.5
Obligations Under Operating Leases:								
Noncurrent Liability	$ 734.6	$ 71.1	$ 1.9	$ 64.0	$ 211.6	$ 76.0	$ 31.0	$ 34.7
Liability Due Within One Year	234.1	12.0	2.1	15.2	87.3	12.5	5.8	6.5
Total Obligations Under Operating Leases	$ 968.7	$ 83.1	$ 4.0	$ 79.2	$ 298.9	$ 88.5	$ 36.8	$ 41.2

Future minimum lease payments consisted of the following as of December 31, 2019:

Finance Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
2020	$ 72.7	$ 7.3	$ —	$ 9.6	$ 9.4	$ 4.7	$ 3.8	$ 12.9
2021	64.9	6.7	—	8.9	8.7	4.3	3.2	11.9
2022	56.4	6.0	—	8.2	8.0	3.4	2.6	10.6
2023	49.6	5.4	—	7.7	7.5	2.8	2.3	9.8
2024	57.4	4.6	—	7.1	10.8	2.4	1.8	14.2
Later Years	64.4	9.8	—	9.8	16.4	5.7	3.8	6.8
Total Future Minimum Lease Payments	365.4	39.8	—	51.3	60.8	23.3	17.5	66.2
Less: Imputed Interest	58.6	5.7	—	9.5	15.7	3.2	2.4	8.6
Estimated Present Value of Future Minimum Lease Payments	$ 306.8	$ 34.1	$ —	$ 41.8	$ 45.1	$ 20.1	$ 15.1	$ 57.6

Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
2020	$ 269.9	$ 16.0	$ 2.2	$ 18.3	$ 97.0	$ 16.2	$ 7.3	$ 8.6
2021	253.6	15.3	1.2	15.7	92.9	14.2	6.4	8.2
2022	245.6	14.2	0.6	14.7	92.8	13.5	6.0	7.6
2023	74.8	13.0	0.1	11.9	10.1	12.3	5.6	6.4
2024	62.0	11.4	—	9.0	8.6	10.7	4.8	5.0
Later Years	169.7	26.0	—	20.0	21.0	36.5	12.0	11.8
Total Future Minimum Lease Payments	1,075.6	95.9	4.1	89.6	322.4	103.4	42.1	47.6
Less: Imputed Interest	106.9	12.8	0.1	10.4	23.5	14.9	5.3	6.4
Estimated Present Value of Future Minimum Lease Payments	$ 968.7	$ 83.1	$ 4.0	$ 79.2	$ 298.9	$ 88.5	$ 36.8	$ 41.2

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 December 31, 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	$ 47.3
AEP Texas	11.3
APCo	6.6
I&M	4.1
OPCo	7.3
PSO	4.2
SWEPCo	4.8

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 December 31, 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 December 31, 2019 were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2020	$ 147.8	$ 73.9
2021	147.8	73.9
2022	147.5	73.7
Total Future Minimum Lease Payments	$ 443.1	$ 221.5

(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 respective lessors, ensuring future payments under such leases with maturities up to 2027. As of December 31, 2019, the maximum potential amount of future payments required under the guaranteed leases was $55 million. Under the terms of certain of the arrangements, upon the lessors exercising their rights after an event of default by the nonaffiliated party, AEP is entitled to enter into new lease arrangements as a lessee that would have substantially the same terms as the existing leases. Alternatively, for the arrangements with one of the lessors, upon an event of default by the nonaffiliated party and the lessor exercising its rights, payment to the lessor would allow AEP to step into the lessor's rights as well as obtaining title to the assets. Under either situation, AEP would have the ability to utilize the assets in the normal course of barging operations. AEP would also have the right to sell the acquired assets for which it obtained title. As of December 31, 2019, AEP's boat and barge lease guarantee liability was $5 million, of which $2 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 February 2020, the nonaffiliated party filed Chapter 11 bankruptcy. The party entered into a restructuring support agreement and has announced it expects to continue their operations as normal. Management has determined that it is reasonably possible that enforcement of AEP's liability for future payments under these leases will be exercised within the next twelve months. In such an event, if AEP is unable to sell or incorporate any of the acquired assets into its fleet operations, it 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 twelve months ended December 31, 2019.

14. FINANCING ACTIVITIES

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

Common Stock (Applies to AEP)

The following table is a reconciliation of common stock share activity:

Shares of AEP Common Stock	Issued	Held in Treasury	
Balance, December 31, 2016	512,048,520	20,336,592	
Issued	162,124	—	
Treasury Stock Reissued	—	(131,546)	(a)
Balance, December 31, 2017	512,210,644	20,205,046	
Issued	1,239,392	—	
Treasury Stock Reissued	—	(886)	(a)
Balance, December 31, 2018	513,450,036	20,204,160	
Issued	923,595	—	
Balance, December 31, 2019	514,373,631	20,204,160	

(a) Reissued Treasury Stock used to fulfill share commitments related to AEP's Share-based Compensation. See "Shared-based Compensation Plans" section of Note 15 for additional information.

Long-term Debt

The following table details long-term debt outstanding:

Company	Maturity	Weighted-Average Interest Rate as of December 31, 2019	Interest Rate Ranges as of December 31, 2019	Interest Rate Ranges as of December 31, 2018	Outstanding as of December 31, 2019	Outstanding as of December 31, 2018
AEP					(in millions)	
Senior Unsecured Notes	2019-2050	4.29%	2.15%-8.13%	2.15%-8.13%	$ 21,180.7	$ 18,903.3
Pollution Control Bonds (a)	2019-2038 (b)	2.75%	1.35%-5.38%	1.60%-6.30%	1,998.8	1,643.8
Notes Payable – Nonaffiliated (c)	2019-2032	3.27%	2.42%-6.37%	3.20%-6.37%	234.3	204.7
Securitization Bonds	2019-2029 (d)	3.23%	1.98%-5.31%	1.98%-5.31%	1,025.1	1,111.4
Spent Nuclear Fuel Obligation (e)					279.8	273.6
Junior Subordinated Notes (f)	2022	3.40%	3.40%		787.8	—
Other Long-term Debt	2019-2059	3.03%	1.15%-13.718%	1.15%-13.718%	1,219.0	1,209.9
Total Long-term Debt Outstanding					$ 26,725.5	$ 23,346.7
AEP Texas						
Senior Unsecured Notes	2019-2050	4.01%	2.40%-6.76%	2.40%-6.76%	$ 3,090.9	$ 2,398.4
Pollution Control Bonds	2020-2030	3.63%	1.75%-4.55%	1.75%-6.30%	490.3	490.9
Securitization Bonds	2020-2029 (d)	3.25%	1.98%-5.31%	1.98%-5.31%	776.8	791.2
Other Long-term Debt	2019-2059	3.06%	3.05%-4.50%	3.94%-4.50%	200.4	200.8
Total Long-term Debt Outstanding					$ 4,558.4	$ 3,881.3
AEPTCo						
Senior Unsecured Notes	2019-2049	3.86%	3.10%-5.52%	2.68%-5.52%	$ 3,427.3	$ 2,823.0
Total Long-term Debt Outstanding					$ 3,427.3	$ 2,823.0
APCo						
Senior Unsecured Notes	2021-2049	5.12%	3.30%-7.00%	3.30%-7.00%	$ 3,442.7	$ 3,047.3
Pollution Control Bonds (a)	2019-2038 (b)	2.64%	1.67%-5.38%	1.70%-5.38%	546.1	616.0
Securitization Bonds	2023-2028 (d)	3.17%	2.008%-3.772%	2.008%-3.772%	248.3	272.3
Other Long-term Debt	2019-2026	3.14%	2.97%-13.718%	3.74%-13.718%	126.7	127.0
Total Long-term Debt Outstanding					$ 4,363.8	$ 4,062.6
I&M						
Senior Unsecured Notes	2023-2048	4.38%	3.20%-6.05%	3.20%-6.05%	$ 2,150.7	$ 2,149.0
Pollution Control Bonds (a)	2019-2025 (b)	2.55%	1.79%-3.05%	1.81%-3.05%	240.0	264.5
Notes Payable – Nonaffiliated (c)	2019-2024	2.49%	2.42%-2.80%	3.20%-3.38%	168.7	135.8
Spent Nuclear Fuel Obligation (e)					279.8	273.6
Other Long-term Debt	2021-2025	3.09%	2.93%-6.00%	3.66%-6.00%	211.0	212.5
Total Long-term Debt Outstanding					$ 3,050.2	$ 3,035.4
OPCo						
Senior Unsecured Notes	2021-2049	5.20%	4.00%-6.60%	4.15%-6.60%	$ 2,081.0	$ 1,635.5
Pollution Control Bonds	2038			5.80%	—	32.3
Securitization Bonds	2019 (d)			2.049%	—	47.8
Other Long-term Debt	2028	1.15%	1.15%	1.15%	1.0	1.0
Total Long-term Debt Outstanding					$ 2,082.0	$ 1,716.6
PSO						
Senior Unsecured Notes	2019-2049	4.55%	3.05%-6.625%	3.05%-6.625%	$ 1,245.6	$ 1,144.9
Pollution Control Bonds	2020	4.45%	4.45%	4.45%	12.7	12.6
Other Long-term Debt	2019-2027	3.19%	3.00%-3.20%	3.00%-3.72%	127.9	129.5
Total Long-term Debt Outstanding					$ 1,386.2	$ 1,287.0
SWEPCo						
Senior Unsecured Notes	2022-2048	4.04%	2.75%-6.20%	2.75%-6.20%	$ 2,428.9	$ 2,427.0
Pollution Control Bonds	2019			1.60%	—	53.5

Notes Payable – Nonaffiliated (c)	2024-2032	5.26%	4.58%-6.37%	4.58%-6.37%	65.6	68.9
Other Long-term Debt	2020-2035	3.55%	3.08%-4.68%	3.75%-4.68%	161.1	164.0
Total Long-term Debt Outstanding					$ 2,655.6	$ 2,713.4

(a) For certain series of Pollution Control Bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.
(b) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets.
(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(d) Dates represent the scheduled final payment dates for the securitization bonds. The legal maturity date is one to two years later. These bonds have been classified for maturity and repayment purposes based on the scheduled final payment date.
(e) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of SNF. See “Spent Nuclear Fuel Disposal” section of Note 6 for additional information.
(f) See “Equity Units” section below for additional information.

As of December 31, 2019, outstanding long-term debt was payable as follows:

		AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
						(in millions)				
2020	$	1,598.7		$ 392.1	$ —	$ 215.6	$ 139.7	$ 0.1	$ 13.2	$ 121.2
2021		2,022.7		88.7	50.0	393.0	291.5	500.1	250.5	6.2
2022		3,014.6	(a)	716.0	104.0	355.4	26.8	0.1	125.5	281.2
2023		739.9		218.5	60.0	26.6	259.2	0.1	0.6	6.2
2024		706.5		96.0	95.0	113.5	4.2	0.1	0.6	31.2
After 2024		18,863.1		3,081.4	3,156.0	3,296.9	2,355.3	1,600.5	1,001.4	2,231.7
Principal Amount		26,945.5		4,592.7	3,465.0	4,401.0	3,076.7	2,101.0	1,391.8	2,677.7
Unamortized Discount, Net and Debt Issuance Costs		(220.0)		(34.3)	(37.7)	(37.2)	(26.5)	(19.0)	(5.6)	(22.1)
Total Long-term Debt Outstanding	$	26,725.5		$ 4,558.4	$ 3,427.3	$ 4,363.8	$ 3,050.2	$ 2,082.0	$ 1,386.2	$ 2,655.6

(a) Amount includes $805 million of Junior Subordinated Notes. See “Equity Units” section below for additional information.

As of December 31, 2019, trustees held, on behalf of AEP, $35 million of their reacquired Pollution Control Bonds. Of this total, $35 million related to OPCo. In January 2020, those Pollution Control Bonds were redeemed.

Long-term Debt Subsequent Events

In January and February 2020, AEP Texas retired $111 million and $3 million, respectively, of Securitization Bonds.

In January and February 2020, I&M retired $8 million and $5 million, respectively, of Notes Payable related to DCC Fuel.

In January 2020, Transource Energy issued $4 million of variable rate Other Long-term Debt due in 2023.

In February 2020, APCo retired $12 million of Securitization 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 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 1.6% of consolidated tangible net assets as of December 31, 2019. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreement.

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. The Federal Power Act also creates a reserve on retained 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 most restrictive dividend limitation for certain AEP subsidiaries is through the Federal Power Act restriction, while for other AEP subsidiaries the most restrictive dividend limitation is through the credit agreements. As of December 31, 2019, the maximum amount of restricted net assets of AEP's subsidiaries that may not be distributed to the Parent in the form of a loan, advance or dividend was $13.2 billion.

The Federal Power Act restriction limits the ability of the AEP subsidiaries owning hydroelectric generation to pay dividends out of retained earnings. Additionally, the credit agreement covenant restrictions can limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. As of December 31, 2019, the amount of any such restrictions were as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Restricted Retained Earnings	$ 1,741.4 (a)	$ 385.0	$ —	$ 26.3	$ 524.5	$ —	$ 153.0	$ 534.5

(a) Includes the restrictions of consolidated and non-consolidated subsidiaries.

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. As of December 31, 2019, AEP had $7.2 billion of available retained earnings to pay dividends to common shareholders. AEP paid $1.3 billion, $1.3 billion and $1.2 billion of dividends to common shareholders for the years ended December 31, 2019, 2018 and 2017, respectively.

Lines of Credit and Short-term Debt (Applies to AEP and SWEPCo)

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. As of December 31, 2019, AEP had a $4 billion revolving credit facility to support its commercial paper program. The commercial paper program for the year ended 2019, had a weighted-average interest rate of 2.51% and a maximum amount outstanding of $2.2 billion. AEP's outstanding short-term debt was as follows:

		December 31,			
		2019		2018	
Company	**Type of Debt**	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
		(in millions)		**(in millions)**	
AEP	Securitized Debt for Receivables (b)	$ 710.0	2.42%	$ 750.0	2.16%
AEP	Commercial Paper	2,110.0	2.10%	1,160.0	2.96%
SWEPCo	Notes Payable	18.3	3.29%	—	—%
	Total Short-term Debt	$ 2,838.3		$ 1,910.0	

(a) Weighted-average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Corporate Borrowing Program – AEP System (Applies to Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; 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 December 31, 2019 and 2018 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2019:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2019	Authorized Short-term Borrowing Limit	
	(in millions)						
AEP Texas	$ 390.7	$ 213.1	$ 239.3	$ 194.4	$ 199.7	$ 500.0	
AEPTCo	374.9	244.4	152.0	52.8	(119.0)	795.0	(a)
APCo	270.0	232.2	115.9	51.9	(214.6)	500.0	
I&M	158.8	66.0	71.5	16.2	(101.2)	500.0	
OPCo	291.2	178.6	129.2	50.1	(131.0)	500.0	
PSO	140.5	215.6	63.9	98.3	38.8	300.0	
SWEPCo	105.1	81.4	53.3	13.6	(59.9)	350.0	

Year Ended December 31, 2018:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2018	Authorized Short-term Borrowing Limit	
	(in millions)						
AEP Texas	$ 390.6	$ 106.9	$ 176.0	$ 47.1	$ (216.0)	$ 500.0	
AEPTCo	371.3	276.4	177.9	58.4	35.8	795.0	(a)
APCo	295.5	23.7	175.3	23.3	(182.6)	600.0	
I&M	322.1	657.8	255.5	110.7	11.6	500.0	
OPCo	270.8	225.0	167.8	189.4	(114.1)	500.0	
PSO	193.7	31.8	104.5	12.9	(105.5)	300.0	
SWEPCo	200.1	533.7	143.2	268.1	81.4	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 tables 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 December 31, 2019 and 2018 are included in Advances to Affiliates on each subsidiaries' balance sheets. The Nonutility Money Pool participants' money pool activity is described in the following tables:

Year Ended December 31, 2019:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2019
		(in millions)	
AEP Texas	$ 8.0	$ 7.7	$ 7.5
SWEPCo	2.1	2.0	2.1

Year Ended December 31, 2018:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2018
		(in millions)	
AEP Texas	$ 8.4	$ 8.1	$ 8.0
SWEPCo	2.0	2.0	2.0

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 December 31, 2019 and 2018 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets. AEPTCo's direct financing activities with AEP and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2019:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2019	Loans to AEP as of December 31, 2019	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 1.3	$ 153.5	$ 1.3	$ 68.0	$ 1.3	$ 68.7	$ 75.0	(a)

Year Ended December 31, 2018:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2018	Loans to AEP as of December 31, 2018	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 1.2	$ 104.7	$ 1.1	$ 49.8	$ 1.2	$ 16.9	$ 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:

	Years Ended December 31,		
	2019	2018	2017
Maximum Interest Rate	3.43%	2.97%	1.85%
Minimum Interest Rate	1.77%	1.81%	0.92%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Years Ended December 31,			Average Interest Rate for Funds Loaned to the Utility Money Pool for the Years Ended December 31,		
Company	2019	2018	2017	2019	2018	2017
AEP Texas	2.63%	2.26%	1.29%	2.03%	2.29%	1.26%
AEPTCo	2.64%	2.27%	1.36%	2.41%	2.10%	1.27%
APCo	2.45%	2.26%	1.28%	2.66%	2.21%	1.29%
I&M	2.34%	2.16%	1.27%	2.60%	2.08%	1.29%
OPCo	2.67%	2.18%	1.37%	2.68%	2.47%	0.98%
PSO	2.85%	2.27%	1.32%	2.27%	1.98%	—%
SWEPCo	2.72%	2.31%	1.28%	2.22%	2.00%	0.98%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Nonutility Money Pool are summarized in the following table:

Year Ended December 31,	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
2019	AEP Texas	3.02%	1.91%	2.56%
2019	SWEPCo	3.02%	1.91%	2.55%
2018	AEP Texas	2.97%	1.83%	2.36%
2018	SWEPCo	2.97%	1.83%	2.36%
2017	AEP Texas	1.85%	—%	1.32%
2017	SWEPCo	1.85%	—%	1.32%

AEPTCo's maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following table:

Year Ended December 31,	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%	1.91%	3.02%	1.91%	2.55%	2.51%
2018	2.97%	1.76%	2.97%	1.76%	2.36%	2.36%
2017	1.85%	0.92%	1.85%	0.92%	1.33%	1.36%

Interest expense and interest income related to the Utility Money Pool, Nonutility Money Pool and direct borrowing financing relationship are included in Interest Expense and Interest Income, respectively, on each of the Registrant Subsidiaries' statements of income. The interest expense and interest income related to the corporate borrowing programs were immaterial for the years ended December 31, 2019, 2018 and 2017.

Credit Facilities

See "Letters of Credit" section of Note 6 for additional information.

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:

	Years Ended December 31,		
	2019	2018	2017
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	2.42%	2.16%	1.22%
Net Uncollectible Accounts Receivable Written Off	$ 26.6	$ 27.6	$ 23.4

	December 31,	
	2019	2018
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 841.8	$ 972.5
Short-term – Securitized Debt of Receivables	710.0	750.0
Delinquent Securitized Accounts Receivable	39.6	50.3
Bad Debt Reserves Related to Securitization	32.1	27.5
Unbilled Receivables Related to Securitization	266.8	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 AEPTCo and AEP Texas)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were:

	December 31,	
Company	2019	2018
	(in millions)	
APCo	$ 120.9	$ 133.3
I&M	141.8	152.9
OPCo	330.3	395.2
PSO	101.1	109.7
SWEPCo	125.2	150.3

The fees paid to AEP Credit for customer accounts receivable sold were:

	Years Ended December 31,		
Company	2019	2018	2017
	(in millions)		
APCo	$ 7.4	$ 7.0	$ 5.6
I&M	11.1	9.2	6.7
OPCo	27.1	26.3	21.7
PSO	7.8	7.9	7.0
SWEPCo	10.2	8.9	7.2

The proceeds on the sale of receivables to AEP Credit were:

	Years Ended December 31,		
Company	2019	2018	2017
	(in millions)		
APCo	$ 1,310.3	$ 1,421.0	$ 1,372.8
I&M	1,824.2	1,843.0	1,612.9

OPCo	2,293.6	2,674.5	2,339.0
PSO	1,442.5	1,484.6	1,337.0
SWEPCo	1,618.5	1,736.1	1,563.4

15. STOCK-BASED COMPENSATION

The disclosures in this note apply to AEP only. The impact of AEP's share-based compensation plans is insignificant to the financial statements of the Registrant Subsidiaries.

Awards under AEP's long-term incentive plan may be granted to employees and directors. The Amended and Restated American Electric Power System Long-Term Incentive Plan (the "Prior Plan"), was replaced prospectively for new grants by the American Electric Power System 2015 Long-Term Incentive Plan (the "2015 LTIP") effective in April 2015. The 2015 LTIP was subsequently amended in September 2016. The 2015 LTIP provides for a maximum of 10 million AEP common shares to be available for grant to eligible employees and directors. As of December 31, 2019, 7,667,992 shares remained available for issuance under the 2015 LTIP. No new awards may be granted under the Prior Plan. The 2015 LTIP awards may be stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards. Shares issued pursuant to a stock option or a stock appreciation right reduce the shares remaining available for grants under the 2015 LTIP by 0.286 of a share. Shares issued for any other awards that settles in AEP stock reduce the shares remaining available for grants under the 2015 LTIP by one share. Cash settled awards do not reduce the number of shares remaining available under the 2015 LTIP. The following sections provide further information regarding each type of stock-based compensation award granted under these plans.

Performance Shares

Performance units granted prior to 2017 were settled in cash rather than AEP common stock and did not reduce the number of shares remaining available under the 2015 LTIP. Those performance units had a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. Performance shares granted in and after 2017 are settled in AEP common stock and will reduce the aggregate share authorization. In all cases the number of performance shares held at the end of the three-year performance period is multiplied by the performance score for such period to determine the actual number of performance shares that participants realize. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the Human Resources Committee of AEP's Board of Directors (HR Committee).

Certain employees must satisfy a minimum stock ownership requirement. If those employees have not met their stock ownership requirement, a portion or all of their performance shares are mandatorily deferred as AEP career shares to the extent needed to meet their stock ownership requirement. AEP career shares are a form of non-qualified deferred compensation that has a value equivalent to a share of AEP common stock. AEP career shares are settled in AEP common stock after the participant's termination of employment.

AEP career shares are recorded in Paid-in Capital on the balance sheets. Amounts equivalent to cash dividends on both performance shares and AEP career shares accrue as additional shares. Management records compensation cost for performance shares over an approximately three-year vesting period. The liability for the pre-2017 performance units was recorded in Employee Benefits and Pension Obligations on the balance sheets and was adjusted for changes in value. Performance shares are recorded as mezzanine equity on the balance sheets and compensation cost is calculated at fair value using two equally weighted metrics. The first metric is a total shareholder return measure, which is valued based on a third-party Monte Carlo valuation. The value related to this metric does not change over the three-year vesting period. The second metric is a three-year cumulative earnings per share metric which is adjusted quarterly for changes in performance relative to a target approved by the HR Committee.

The HR Committee awarded performance shares and reinvested dividends on outstanding performance shares and AEP career shares as follows:

Performance Shares		2019		2018		2017
	Years Ended December 31,					
Awarded Shares (in thousands)		535.0		581.4		590.7
Weighted Average Share Fair Value at Grant Date	$	83.21	$	67.21	$	69.78
Vesting Period (in years)		3		3		3

Performance Shares and AEP Career Shares (Reinvested Dividends Portion)		2019		2018		2017
	Years Ended December 31,					
Awarded Shares (in thousands) (a)		66.4		80.2		74.6
Weighted Average Fair Value at Grant Date	$	88.73	$	70.58	$	72.35
Vesting Period (in years)		(b)		(b)		(b)

(a) All awarded dividends in 2019 were equity awards and awarded dividends in both 2018 and 2017 were a mix of equity awards and liability awards.
(b) The vesting period for the reinvested dividends on performance shares is equal to the remaining life of the related performance shares. Dividends on AEP career shares vest immediately when the dividend is awarded but are not settled in AEP common stock until after the participant's AEP employment ends.

Performance scores and final awards are determined and approved by the HR Committee in accordance with the pre-established performance measures within approximately two months after the end of the performance period. The performance scores for all performance periods were dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to a peer group of similar companies and (b) three-year cumulative earnings per share measured relative to a target approved by the HR Committee.

The certified performance scores and shares earned for the three-year periods were as follows:

Performance Shares	2019	2018	2017
	Years Ended December 31,		
Certified Performance Score	132.7%	136.7%	164.8%
Performance Shares Earned	792,897	820,780	956,055
Performance Shares Mandatorily Deferred as AEP Career Shares	10,063	11,248	20,213
Performance Shares Voluntarily Deferred into the Incentive Compensation Deferral Program	49,392	56,826	47,177
Performance Shares to be Settled (a)	733,442	752,706	888,665

(a) Performance shares settled for the three-year period ended December 31, 2019 settled in AEP common stock. Performance units settled for the three-year period ended December 31, 2018 and 2017 settled in cash.

The settlements were as follows:

Performance Units and AEP Career Shares		2019		2018		2017
	Years Ended December 31,					
	(in millions)					
Cash Settlements for Performance Units	$	58.3	$	66.9	$	64.9
AEP Common Stock Settlements for Career Share Distributions		6.6		5.1		0.4

A summary of the status of AEP's nonvested Performance Shares as of December 31, 2019 and changes during the year ended December 31, 2019 were as follows:

Nonvested Performance Shares	Shares	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2019	1,171.3	$ 66.01
Granted	582.5	80.30
Vested (a)	(597.5)	65.42
Forfeited	(42.9)	70.32
Nonvested as of December 31, 2019	1,113.4	73.64

(a) The vested Performance Shares will be converted to 733 thousand shares based on the closing share price on the day before settlement.

Monte Carlo Valuation

AEP engages a third-party for a Monte Carlo valuation to calculate half of the fair value for the performance shares awarded during and after 2017. The valuations use a lattice model and the expected volatility assumptions used were the historical volatilities for AEP and the members of their peer group. The assumptions used in the Monte Carlo valuations were as follows:

	Years Ended December 31,		
Monte Carlo Valuation	**2019**	**2018**	**2017**
Valuation Period (in years) (a)	2.87	2.87	2.86
Expected Volatility Minimum	14.83%	14.77%	15.65%
Expected Volatility Maximum	25.57%	26.72%	27.19%
Expected Volatility Average	17.39%	17.90%	19.07%
Dividend Rate (b)	—%	—%	—%
Risk Free Rate	2.49%	2.34%	1.44%

(a) Period from award date to vesting date.
(b) Equivalent to reinvesting dividends.

Restricted Stock Units

The HR Committee grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. The RSUs accrue dividends as additional RSUs. The additional RSUs granted as dividends vest on the same date as the underlying RSUs. RSUs are converted into shares of AEP common stock upon vesting, except the RSUs granted prior to 2017 to AEP's executive officers which settled in cash. Executive officers are those officers who are subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934. For RSUs that settle in shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of RSUs granted by the grant date market closing price. For RSUs that settled in cash, compensation cost is recorded over the vesting period and adjusted for changes in fair value until vested. The fair value at vesting was determined by multiplying the number of RSUs vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is approximately 40 months from the grant date.

The HR Committee awarded RSUs, including additional units awarded as dividends, as follows:

Restricted Stock Units	Years Ended December 31, 2019	2018	2017
Awarded Units (in thousands)	304.8	260.0	255.8
Weighted Average Grant Date Fair Value	$ 81.57	$ 67.96	$ 65.26

The total fair value and total intrinsic value of restricted stock units vested were as follows:

Restricted Stock Units	Years Ended December 31, 2019	2018	2017
		(in millions)	
Fair Value of Restricted Stock Units Vested	$ 16.3	$ 16.6	$ 16.1
Intrinsic Value of Restricted Stock Units Vested (a)	21.6	19.2	20.0

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of AEP's nonvested RSUs as of December 31, 2019 and changes during the year ended December 31, 2019 were as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2019	489.1	$ 66.01
Granted	304.8	81.57
Vested	(253.7)	64.44
Forfeited	(23.3)	70.27
Nonvested as of December 31, 2019	516.9	75.55

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2019 was $49 million and the weighted average remaining contractual life was 1.79 years.

Other Stock-Based Plans

AEP also has a Stock Unit Accumulation Plan for Non-Employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to non-employee directors are fully vested on their grant date. Stock units are settled in cash upon termination of board service or up to 10 years later if the participant so elects. Cash settlements for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date. After five years of service on the Board of Directors, non-employee directors receive subsequent AEP stock units as contributions to an AEP stock fund awarded under the Stock Unit Accumulation Plan. Such amounts may be exchanged into other market-based investments that are similar to the investment options available to employees that participate in AEP's Incentive Compensation Deferral Plan.

Management records compensation cost for stock units when the units are awarded and adjusts the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

For the years ended December 31, 2019, 2018 and 2017, cash settlements for stock unit distributions were immaterial.

The Board of Directors awarded stock units, including units awarded for dividends, as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2019	2018	2017
Awarded Units (in thousands)	10.0	11.4	14.8
Weighted Average Grant Date Fair Value	$ 89.13	$ 70.41	$ 70.79

Share-based Compensation Plans

For share-based payment arrangements the compensation cost, the actual tax benefit from the tax deductions for compensation cost recognized in income and the total compensation cost capitalized were as follows:

Share-based Compensation Plans	Years Ended December 31, 2019	2018	2017
		(in millions)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 57.9	$ 53.2	$ 79.5
Actual Tax Benefit (b)	8.4	7.7	18.9
Total Compensation Cost Capitalized	20.0	19.7	26.4

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

(b) In December 2017, Tax Reform modified Section 162(m) of the Internal Revenue Code. Beginning after 2017, AEP can generally no longer deduct certain compensation expense in excess of $1 million for certain named executive officers. This will reduce the tax benefit going forward.

As of December 31, 2019, there was $73 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the 2015 LTIP. Unrecognized compensation cost related to unvested share-based arrangements will change as the fair value of performance shares are adjusted each period and as forfeitures for all award types are realized. AEP's unrecognized compensation cost will be recognized over a weighted-average period of 1.43 years.

Under the 2015 LTIP, AEP is permitted to use authorized but unissued shares, treasury shares, shares acquired in the open market specifically for distribution under these plans, or any combination thereof to fulfill share commitments. AEP's current practice is to use authorized but unissued shares to fulfill share commitments. The number of shares used to fulfill share commitments is generally reduced to offset AEP's tax withholding obligation.

16. <u>RELATED PARTY TRANSACTIONS</u>

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

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 12 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Power Coordination Agreement (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. With the transfer of OPCo's generation assets to AGR in 2014, AEPSC conducts only gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

System Integration Agreement (Applies to APCo, I&M, PSO and SWEPCo)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

The tables below represent revenues from affiliates, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2019							
Direct Sales to East Affiliates	$ —	$ —	$ 128.6	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	—	—
Auction Sales to OPCo (a)	—	—	11.4	6.7	—	—	—
Direct Sales to AEPEP	157.2	—	—	—	—	—	(0.1)
Transmission Revenues	—	795.5	58.5	0.7	7.7	1.3	3.6
Other Revenues	3.3	11.2	6.8	3.1	19.6	4.8	1.4
Total Affiliated Revenues	$ 160.5	$ 806.7	$ 205.3	$ 10.5	$ 27.3	$ 6.1	$ 4.9

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2018							
Direct Sales to East Affiliates	$ —	$ —	$ 133.2	$ 0.1	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	—	—
Auction Sales to OPCo (a)	—	—	5.8	7.1	—	—	—
Direct Sales to AEPEP	103.6	—	—	—	—	—	—
Transmission Revenues	—	591.4	36.4	11.7	3.9	0.9	26.9
Other Revenues	1.6	7.5	6.0	3.2	17.1	4.5	1.5
Total Affiliated Revenues	$ 105.2	$ 598.9	$ 181.4	$ 22.1	$ 21.0	$ 5.4	$ 28.4

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2017							
Direct Sales to East Affiliates	$ —	$ —	$ 130.4	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	3.8	—	—	—
Auction Sales to OPCo (a)	—	—	1.0	—	—	—	—
Direct Sales to AEPEP	63.6	—	—	—	—	—	(0.2)
Transmission Revenues	—	559.6	34.1	(4.4)	6.2	—	24.2
Other Revenues	2.1	8.5	6.5	2.4	18.2	4.3	1.9
Total Affiliated Revenues	$ 65.7	$ 568.1	$ 172.0	$ 1.8	$ 24.4	$ 4.3	$ 25.9

(a) Refer to the Ohio Auctions section below for further information regarding these amounts.

The tables below represent the purchased power expenses incurred for purchases from affiliates. AEP Texas, AEPTCo, APCo, PSO and SWEPCo did not purchase any power from affiliates for the years ended December 31, 2019, 2018 and 2017.

Related Party Purchases	I&M	OPCo
	(in millions)	
Year Ended December 31, 2019		
Auction Purchases from AEPEP (a)	$ —	$ 64.6
Auction Purchases from AEP Energy (a)	—	69.9
Auction Purchases from AEPSC (a)	—	21.5
Direct Purchases from AEGCo	214.9	—
Total Affiliated Purchases	$ 214.9	$ 156.0

Related Party Purchases	I&M	OPCo
	(in millions)	
Year Ended December 31, 2018		
Auction Purchases from AEPEP (a)	$ —	$ 79.7
Auction Purchases from AEP Energy (a)	—	41.0
Auction Purchases from AEPSC (a)	—	14.6
Direct Purchases from AEGCo	237.9	—
Total Affiliated Purchases	$ 237.9	$ 135.3

Related Party Purchases	I&M	OPCo
	(in millions)	
Year Ended December 31, 2017		
Auction Purchases from AEPEP (a)	$ —	$ 96.5
Auction Purchases from AEP Energy (a)	—	5.5
Auction Purchases from AEPSC (a)	—	6.5
Direct Purchases from AEGCo	223.9	—
Total Affiliated Purchases	$ 223.9	$ 108.5

(a) Refer to the Ohio Auctions section below for further information regarding this amount.

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates, respectively, on the Registrant Subsidiaries' statements of income. Since the Registrant Subsidiaries are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

PJM and SPP Transmission Service Charges (Applies to all Registrant Subsidiaries except AEP Texas)

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the Transmission Agreement (TA), which defines how transmission costs through the PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to AEP East Companies through the PJM OATT.

The following table shows the net transmission service charges recorded by APCo, I&M and OPCo:

	Years Ended December 31,		
Company	2019	2018	2017
		(in millions)	
APCo	$ 222.3	$ 128.3	$ 158.2
I&M	143.5	91.4	103.8
OPCo	373.4	210.1	248.6

The charges shown above are recorded in Other Operation expenses on the statements of income.

PSO, SWEPCo and AEPSC are parties to the Transmission Coordination Agreement (TCA) in connection with the operation of the transmission assets of PSO and SWEPCo. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such a tariff.

Under the TCA, the parties to the agreement delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to PSO and SWEPCo through the SPP OATT.

The following table shows the net transmission service charges recorded by PSO and SWEPCo:

	Years Ended December 31,		
Company	**2019**	**2018**	**2017**
	(in millions)		
PSO	$ 46.9	$ 65.9	$ 56.0
SWEPCo	20.1	10.5	6.6

The charges shown above are recorded in Other Operation expenses on the statements of income.

AEPTCo provides transmission services to affiliates in accordance with the OATT, TA and TCA. AEPTCo recorded affiliated transmission revenues in Sales to AEP Affiliates on the statements of income. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

ERCOT Transmission Service Charges (Applies to AEP and AEP Texas)

Pursuant to an order from the PUCT, ETT bills AEP Texas for its ERCOT wholesale transmission services. ETT billed AEP Texas $27 million, $27 million and $30 million for transmission services in 2019, 2018 and 2017, respectively. The billings are recorded in Other Operation expenses on AEP Texas' statements of income.

Oklaunion PPA between AEP Texas and AEPEP (Applies to AEP Texas)

In 2007, AEP Texas entered into a PPA with an affiliate, AEPEP, whereby AEP Texas agrees to sell AEPEP 100% of AEP Texas' capacity and associated energy from its undivided interest (54.69%) in the Oklaunion Power Station. AEPEP pays AEP Texas for the capacity and associated energy delivered to the delivery point, the sum of fuel, operation and maintenance, depreciation, capacity and all taxes other than federal income taxes applicable. A portion of the payment is fixed and is payable regardless of the level of output. There are no penalties if AEP Texas fails to maintain a minimum availability level or exceeds a maximum heat rate level. The PPA was approved by the FERC. AEP Texas recognizes revenues for the fuel, operations and maintenance and all other taxes as billed. Revenue is recognized for the capacity and depreciation billed to AEPEP, on a straight-line basis over the term of the PPA as these represent the minimum payments due. In September 2018, the co-owners of Oklaunion Power Station voted to close the plant in 2020. Effective October 2018, AEP Texas increased depreciation expense to ensure the plant balances are fully depreciated as of September 2020 and recovered through the PPA billings to AEPEP. Under the early termination provisions of the PPA, AEPEP expects to pay AEP Texas the full Property, Plant and Equipment balance through depreciation payments over the remaining period of operation of the plant, which is currently estimated to be September 2020.

AEP Texas recorded revenue of $157 million, $104 million and $64 million from AEPEP for the years ended December 31, 2019, 2018 and 2017, respectively. These amounts are included in Sales to AEP Affiliates on AEP Texas' statements of income.

Joint License Agreement (Applies to AEPTCo, APCo, I&M, OPCo and PSO)

AEPTCo entered into a 50-year joint license agreement with APCo, I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. In addition, AEPTCo entered into a 5-year joint license agreement with APCo and WPCo. After the expiration of these agreements, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. AEPTCo recorded the following costs in Other Operation expense related to these agreements:

	Years Ended December 31,		
Billing Company	**2019**	**2018**	**2017**
	(in millions)		
APCo	$ 0.2	$ —	$ —
I&M	1.5	2.2	1.4
KPCo	0.3	0.2	0.2
OPCo	2.2	2.9	2.4
PSO	0.3	0.3	0.3
WPCo	0.1	—	—

APCo, I&M, KPCo, OPCo, PSO and WPCo recorded income related to these agreements in Sales to AEP Affiliates on the statements of income.

Ohio Auctions (Applies to APCo, I&M and OPCo)

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy, AEPEP, APCo, KPCo, I&M and WPCo participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions and see "Ohio ESP Filings" section of Note 4 for additional information.

Unit Power Agreements (Applies to I&M)

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between AEGCo and KPCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

Cook Coal Terminal (Applies to I&M, PSO and SWEPCo)

Cook Coal Terminal, which is owned by AEGCo, performs coal transloading and storage services at cost for I&M. The coal transloading costs were $13 million, $12 million and $10 million in 2019, 2018 and 2017, respectively. I&M recorded the cost of transloading services in Fuel on the balance sheets.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M, PSO and SWEPCo. The railcar maintenance costs were as follows:

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
I&M	$ 1.3	$ 1.5	$ 1.3
PSO	0.8	0.7	0.5
SWEPCo	4.0	3.4	3.5

I&M, PSO and SWEPCo recorded the cost of the railcar maintenance services in Fuel on the balance sheets.

I&M Barging, Urea Transloading and Other Services (Applies to APCo and I&M)

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
AEGCo	$ 14.9	$ 19.9	$ 15.3
AGR	—	—	0.1
APCo	38.9	35.1	37.2
KPCo	4.8	4.2	5.0
WPCo	4.8	4.2	5.0

Central Machine Shop (Applies to APCo, I&M, PSO and SWEPCo)

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. The AEP subsidiaries recorded these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the following affiliates:

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
AGR	$ 0.8	$ 1.6	$ 1.2
I&M	2.3	2.4	2.7
KPCo	1.4	1.7	1.8
PSO	1.1	0.5	1.1
SWEPCo	1.1	0.7	0.8

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following tables show the sales and purchases, recorded at net book value:

Sales

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
AEP Texas	$ 0.9	$ 0.3	$ 0.2
APCo	5.5	5.4	3.5
I&M	7.5	8.2	5.0
OPCo	7.0	10.7	2.9
PSO	0.8	1.0	1.5
SWEPCo	0.2	0.8	0.5

Purchases

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
AEP Texas	$ 0.3	$ 0.1	$ 0.4
AEPTCo	10.2	18.5	9.1
APCo	6.0	0.6	0.9
I&M	0.9	2.0	3.5
OPCo	3.0	2.8	1.6
PSO	0.5	1.3	0.2
SWEPCo	0.7	0.8	0.4

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Sempra Renewables LLC PPAs (Applies to I&M, OPCo and SWEPCo)

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation. The operating wind generation portfolio includes seven wind farms. Prior to the acquisition, two wind farms had existing PPAs with I&M, OPCo and SWEPCo. See "Acquisitions" section of Note 7 for additional information.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP’s 11-state service area. Charitable contributions to the AEP Foundation were recorded in Other Operation on the statements of income. The contributions recorded were as follows:

Company	Year Ended December 31, 2019
	(in millions)
AEP	$ 50.0
AEP Texas	6.2
AEPTCo	6.5
APCo	8.9
I&M	9.0
OPCo	5.4
PSO	3.4
SWEPCo	5.5

17. VARIABLE INTEREST ENTITIES AND EQUITY METHOD INVESTMENTS

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

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether AEP is the primary beneficiary of a VIE, management considers whether AEP has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently.

AEP 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. AEP has not provided material financial or other support that was not previously contractually required to any of its consolidated VIEs. 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.

Consolidated Variable Interests Entities (Applies to all Registrants except AEPTCo and PSO)

Sabine

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2019, 2018 and 2017 were $110 million, $152 million and $137 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

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. SWEPCo recovers these costs through its fuel clauses. As of December 31, 2019, SWEPCo has recorded $83 million of mine reclamation costs in Asset Retirement Obligations and has collected $78 million through a rider for reclamation costs. The remaining $5 million is recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

DCC Fuel

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2019, 2018 and 2017 were $95 million, $113 million and $136 million, respectively. The leases were recorded as finance leases on I&M's balance sheets as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The finance leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

Transition Funding

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that AEP Texas is the primary beneficiary of Transition Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Transition Funding. The securitized bonds totaled $541 million and $791 million as of December 31, 2019 and 2018, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Transition Funding has securitized transition assets of $389 million and $637 million as of December 31, 2019 and 2018, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from AEP Texas under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Restoration Funding

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 December 31, 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 $232 million as of December 31, 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 Funding's 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 Funding's assets and liabilities on the balance sheets.

Ohio Phase-in-Recovery Funding

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. In July 2019, the securitization bonds matured. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $0 and $48 million as of December 31, 2019 and 2018, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $0 and $13 million as of December 31, 2019 and 2018, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represented the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. The securitization bonds were payable only from and secured by the securitized assets. The bondholders had no recourse to OPCo or any other AEP entity. OPCo acted as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remitted all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on OPCo's balance sheets.

Appalachian Consumer Rate Relief Funding

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $223 million and $272 million as of December 31, 2019 and 2018, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $235 million and $259 million as of December 31, 2019 and 2018, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's balance sheets.

AEP Credit

AEP Credit is a wholly-owned subsidiary of Parent. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third-party financings. Any third-party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on AEP's control of AEP Credit, management concluded that AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables - AEP Credit" section of Note 14.

EIS

AEP's subsidiaries participate in one protected cell of EIS for six lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third-parties access to this insurance. AEP's subsidiaries and any allowed third-parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the years ended December 31, 2019, 2018 and 2017 was $34 million, $34 million and $29 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

Transource Energy

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. Transource Energy's activities consist of the development, construction and operation of FERC-regulated transmission assets in Missouri, West Virginia, Pennsylvania and Maryland. Transource Energy has a credit facility agreement where borrowings are loaned through intercompany lending agreements to its subsidiaries. The creditor to the agreement has no recourse to the general credit of AEP. Transource Energy's credit facility agreement contains certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. For the years ended December 31, 2019, 2018 and 2017, AEP provided capital contributions to Transource Energy of $0, $4 million and $5 million, respectively. See the tables below for the classification of Transource Energy's assets and liabilities on the balance sheets.

Desert Sky Wind Farm LLC and Trent Wind Farm LLC

Desert Sky Wind Farm LLC and Trent Wind Farm LLC (collectively the LLCs) were established for the purpose of repowering, owning and operating wind-powered electric energy generation facilities in Texas. In January 2018, AEP admitted a nonaffiliate as a member of the LLCs to own and repower Desert Sky and Trent. The nonaffiliate contributed full turbine sets to each project in exchange for a 20.1% interest in the LLCs. The nonaffiliates' contribution of $84 million was recorded as Net Property, Plant and Equipment on the balance sheets, which was the fair value as of the contribution date determined based on key input assumptions of the original cost of the full turbine sets and the discounted cash flow benefit associated with the production tax credits available from repowering Desert Sky and Trent based on their expected net capacity, capacity factor and the operational availability. AEP owns 79.9% of the LLCs. As a result, management has concluded that the LLCs are VIEs and that AEP is the primary beneficiary based on its power to direct the activities that most significantly impact their economic performance. Also in January 2018, the LLCs entered into a forward PPA for the sale of power to AEPEP related to deliveries of electricity beginning January 1, 2021 for a 12 year period. Prior to the effective date of the PPA, the LLCs will sell power at market rates into ERCOT. AEP and the nonaffiliate will share tax attributes including PTC and cash distributions from the operation of the LLCs generally consistent with the ownership percentages. See the tables below for the classification of the LLCs' assets and liabilities on the balance sheets.

AEP has a call right, which if exercised, would require the nonaffiliate to sell its noncontrolling interest in the LLCs to AEP. The call exercise period is for ninety days, beginning July 2020 for Trent Wind Farm LLC and August 2020 for Desert Sky Wind Farm LLC. The nonaffiliates' interest in the LLCs is presented as Redeemable Noncontrolling Interest on the balance sheets. The nonaffiliate holds redemption rights, which if exercised, would require AEP to purchase the nonaffiliates' noncontrolling interest in the LLCs. The redemption right exercise period is for ninety days, beginning July 2021 for Trent Wind Farm LLC and August 2021 for Desert Sky Wind Farm LLC. The exercise price for both the call and redemption right are determined using a discounted cash flow model with agreed input assumptions as well as potential updates to certain assumptions reasonably expected based on the actual results of the LLCs. As of December 31, 2019 and 2018, AEP recorded $66 million and $69 million, respectively, of Redeemable Noncontrolling Interest in Mezzanine Equity 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) (collectively 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 December 31, 2019, AEP recorded $128 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 year ended December 31, 2019, the HLBV method resulted in a loss of $6 million 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 302 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 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 East's assets and liabilities on the balance sheets.

AEP recognized $10 million of PTC attributable to Santa Rita East for the year ended December 31, 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 December 31, 2019, AEP recorded $118 million of Noncontrolling Interests related to Santa Rita East in Equity on the balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2019

	Registrant Subsidiaries					
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	AEP Texas Restoration Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding
	(in millions)					
ASSETS						
Current Assets	$ 80.0	$ 86.5	$ 187.0	$ 9.4	$ —	$ 21.5
Net Property, Plant and Equipment	111.6	156.8	—	—	—	—
Other Noncurrent Assets	93.2	82.5	428.1 (a)	234.4 (b)	—	237.5 (c)
Total Assets	$ 284.8	$ 325.8	$ 615.1	$ 243.8	$ —	$ 259.0
LIABILITIES AND EQUITY						
Current Liabilities	$ 50.6	$ 86.4	$ 280.2	$ 16.3	$ —	$ 28.3
Noncurrent Liabilities	233.6	239.4	316.3	226.3	—	228.8
Equity	0.6	—	18.6	1.2	—	1.9
Total Liabilities and Equity	$ 284.8	$ 325.8	$ 615.1	$ 243.8	$ —	$ 259.0

(a) Includes an intercompany item eliminated in consolidation of $39 million.
(b) Includes an intercompany item eliminated in consolidation of $1 million.
(c) Includes an intercompany item eliminated in consolidation of $3 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2019

	Other Consolidated VIEs					
	AEP Credit	Protected Cell of EIS	Transource Energy	Desert Sky and Trent	Apple Blossom and Black Oak	Santa Rita East
	(in millions)					
ASSETS						
Current Assets	$ 842.8	$ 194.6	$ 25.8	$ 7.8	$ 10.1	$ 17.7
Net Property, Plant and Equipment	—	—	424.1	330.6	231.4	465.2
Other Noncurrent Assets	7.1	—	3.2	10.1	13.1	0.3
Total Assets	$ 849.9	$ 194.6	$ 453.1	$ 348.5	$ 254.6	$ 483.2
LIABILITIES AND EQUITY						
Current Liabilities	$ 805.2	$ 40.7	$ 192.4	$ 5.5	$ 5.4	$ 3.9
Noncurrent Liabilities	0.9	78.0	4.8	15.8	4.7	7.5
Equity	43.8	75.9	255.9	327.2	244.5	471.8
Total Liabilities and Equity	$ 849.9	$ 194.6	$ 453.1	$ 348.5	$ 254.6	$ 483.2

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2018

	Registrant Subsidiaries				
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Transition Funding**	**OPCo Ohio Phase-in-Recovery Funding**	**APCo Appalachian Consumer Rate Relief Funding**
	(in millions)				
ASSETS					
Current Assets	$ 70.0	$ 77.6	$ 192.8	$ 29.5	$ 24.8
Net Property, Plant and Equipment	106.9	122.3	—	—	—
Other Noncurrent Assets	98.5	58.4	683.5 (a)	24.2 (b)	261.8 (c)
Total Assets	$ 275.4	$ 258.3	$ 876.3	$ 53.7	$ 286.6
LIABILITIES AND EQUITY					
Current Liabilities	$ 31.1	$ 77.1	$ 271.9	$ 48.5	$ 28.0
Noncurrent Liabilities	244.0	181.2	586.1	3.9	256.7
Equity	0.3	—	18.3	1.3	1.9
Total Liabilities and Equity	$ 275.4	$ 258.3	$ 876.3	$ 53.7	$ 286.6

(a) Includes an intercompany item eliminated in consolidation of $47 million.
(b) Includes an intercompany item eliminated in consolidation of $11 million.
(c) Includes an intercompany item eliminated in consolidation of $3 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2018

	Other Consolidated VIEs			
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**	**Desert Sky and Trent**
	(in millions)			
ASSETS				
Current Assets	$ 974.2	$ 177.8	$ 25.7	$ 6.8
Net Property, Plant and Equipment	—	—	380.3	348.5
Other Noncurrent Assets	6.3	0.1	1.9	—
Total Assets	$ 980.5	$ 177.9	$ 407.9	$ 355.3
LIABILITIES AND EQUITY				
Current Liabilities	$ 923.5	$ 38.6	$ 19.9	$ 8.7
Noncurrent Liabilities	0.8	85.3	160.3	6.2
Equity	56.2	54.0	227.7	340.4
Total Liabilities and Equity	$ 980.5	$ 177.9	$ 407.9	$ 355.3

Non-Consolidated Significant Variable Interests

DHLC

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. The operations of DHLC are governed by the lignite mining agreement among SWEPCo, CLECO and DHLC. SWEPCo and CLECO share the executive board seats and voting rights equally. In accordance with the lignite mining agreement, each entity is responsible for 50% of DHLC's obligations, including debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2019, 2018 and 2017 were $55 million, $58 million and $61 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31,			
	2019		2018	
	As Reported on the Balance Sheet	**Maximum Exposure**	**As Reported on the Balance Sheet**	**Maximum Exposure**
	(in millions)			
Capital Contribution from SWEPCo	$ 7.6	$ 7.6	$ 7.6	$ 7.6
Retained Earnings	17.5	17.5	14.5	14.5
SWEPCo's Share of Obligations	—	130.0	—	167.6
Total Investment in DHLC	$ 25.1	$ 155.1	$ 22.1	$ 189.7

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2019, AEP's ownership in OVEC was 43.47%. Parent owns 39.17% and OPCo owns 4.3%. APCo, I&M and OPCo are members to an intercompany power agreement. The Registrants' power participation ratios are 15.69% for APCo, 7.85% for I&M and 19.93% for OPCo. Participants of this agreement are entitled to receive and are obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2019 and 2018, OVEC's outstanding indebtedness was approximately $1.4 billion and $1.4 billion, respectively. Although they are not an obligor or guarantor, the Registrants' are responsible for their respective ratio of OVEC's outstanding debt through the intercompany power agreement. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6 for additional information.

AEP is not required to consolidate OVEC as it is not the primary beneficiary, although AEP and its subsidiary holds a significant variable interest in OVEC. Power to control decision making that significantly impacts the economic performance of OVEC is shared amongst the owners through their representation on the Board of Directors of OVEC and the representation of the sponsoring companies on the Operating Committee under the intercompany power agreement.

AEP's investment in OVEC was:

	December 31,			
	2019		2018	
	As Reported on the Balance Sheet	**Maximum Exposure**	**As Reported on the Balance Sheet**	**Maximum Exposure**
	(in millions)			
Capital Contribution from AEP	$ 4.4	$ 4.4	$ 4.4	$ 4.4
AEP's Ratio of OVEC Debt (a)	—	588.9	—	604.1
Total Investment in OVEC	$ 4.4	$ 593.3	$ 4.4	$ 608.5

(a) Based on the Registrants' power participation ratios APCo, I&M and OPCo's share of OVEC debt was $213 million, $106 million and $270 million as of December 31, 2019 and $218 million, $109 million and $277 million as of December 31, 2018, respectively.

Power purchased by the Registrant Subsidiaries from OVEC is included in Purchased Electricity for Resale on the statements of income and is shown in the table below:

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
APCo	$ 104.5	$ 100.4	$ 101.0
I&M	52.3	50.2	50.5
OPCo	132.7	127.5	128.2

Potomac-Appalachian Transmission Highline, LLC (PATH)

AEP and FirstEnergy Corp. (FirstEnergy) have a joint venture in PATH. PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. AEP has no interest or control in the "Allegheny Series." AEP is not required to consolidate PATH-WV as AEP is not the primary beneficiary, although AEP holds a significant variable interest in PATH-WV. AEP's equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. AEP and FirstEnergy share the returns and losses equally in PATH-WV. AEP's subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, the transmission project that PATH was intended to develop and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The parties to the case were unable to reach a settlement agreement and in March 2014, settlement judge procedures were terminated. Hearings at the FERC were held in March and April 2015. In April 2015, PATH filed a stipulation agreement with the FERC that agreed to a 50% debt and 50% equity capital structure and a 4.7% cost of long-term debt for the entire amortization period. In September 2015, the ALJ issued an advisory Initial Decision. Additional briefing was submitted during the fourth quarter of 2015. In January 2017, the FERC issued its order on Initial Decision, adopting in part and rejecting in part the ALJ's recommendations. The FERC order included (a) a finding that the PATH Project's abandonment costs were prudently incurred, (b) a finding that the disposition of certain assets was prudent, (c) guidance regarding the future disposition of assets, (d) a reduction of PATH WV's authorized ROE to 8.11% prospectively only after the date of the order, (e) an adjustment of the amortization period to end December 2017, and (f) a credit for certain amounts that were deemed to be not includable in PATH-WV's formula rates.

In February 2017, the PATH Companies filed a request for rehearing of two adverse rulings in the January 2017 FERC order. The request seeks the FERC to reverse its reduction of the PATH Companies 10.4% ROE for the period after January 19, 2017 and to allow the recovery of certain education and outreach costs disallowed by the order. In February 2017, the Edison Electric Institute ("EEI") also filed a request for rehearing recommending reversal of the January 2017 FERC ordered ROE reduction and cost disallowance. The filing of requests for rehearing did not impact the recovery of costs by the PATH Companies under their formula rates or the timing of the compliance filing required by the order, which was filed in March 2017, and updated in May 2017 and August 2017. As a result of the January 2017 FERC order, PATH-WV was required to refund certain amounts that had been collected under its formula rate in its 2018 Projected Transmission Revenue Requirement. PATH-WV refunded $11 million in 2018, including carrying charges, related to the January 2017 order in its 2018 Projected Transmission Revenue Requirement.

In January 2019, the FERC issued an order stating that PATH complied in part, and did not comply in part, with directives of the previous FERC order's mandated compliance filing concerning formula rates and its abandonment recovery. The order included a requirement for PATH to recalculate its recoverable cost of service associated with general advertising costs and provide information regarding land transactions. PATH filed an additional compliance filing, including refund estimates. In connection with its recalculated recoverable cost of service, PATH-WV will refund disallowed costs for general advertising that were previously collected in formula rates. As of December 31, 2019 PATH-WV has $1 million, including carrying charges, recorded as Accumulated Provisions for Rate Refunds that will be refunded in rates effective January 1, 2020.

In January 2020, the FERC issued an order on the PATH Companies' February 2017 request for rehearing. The order included: (a) a request for additional briefs to determine a just and reasonable ROE, (b) confirmation of a previous order stating that PATH's risk profile has decreased due to the PATH Project's abandonment and (c) acceptance of PATH's compliance filing from March 2017 as discussed above, subject to the review of (a). In addition, the order granted rehearing and reversed the disallowance of certain education, outreach and general advertising costs as discussed above. The January 2020 FERC order may be subject to further requests for rehearing or appeal.

AEP's investment in PATH-WV was:

	December 31,			
	2019		2018	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from Parent	$ 18.8	$ 18.8	$ 18.8	$ 18.8
Retained Earnings	(1.7)	(1.7)	(1.4)	(1.4)
Total Investment in PATH-WV	$ 17.1	$ 17.1	$ 17.4	$ 17.4

AEP's investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. If AEP cannot ultimately recover the investment related to PATH-WV, it could reduce future net income and cash flows and impact financial condition.

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Years Ended December 31,		
Company	2019	2018	2017
	(in millions)		
AEP Texas	$ 206.6	$ 184.3	$ 152.6
AEPTCo	242.3	220.4	188.9
APCo	308.3	295.6	268.8
I&M	184.8	173.5	176.0
OPCo	230.4	214.9	195.7
PSO	125.7	121.5	114.7
SWEPCo	169.5	164.4	150.7

The carrying amount and classification of variable interest in AEPSC's accounts payable were as follows:

	December 31,			
	2019		2018	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
AEP Texas	$ 32.4	$ 32.4	$ 22.3	$ 22.3
AEPTCo	33.4	33.4	24.6	24.6
APCo	44.1	44.1	32.2	32.2
I&M	28.6	28.6	23.8	23.8
OPCo	33.2	33.2	23.9	23.9
PSO	18.1	18.1	13.2	13.2
SWEPCo	23.4	23.4	18.4	18.4

AEGCo

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. Total billings to I&M from AEGCo for the years ended December 31, 2019, 2018 and 2017 were $215 million, $238 million and $224 million, respectively. The carrying amounts of I&M's liabilities associated with AEGCo as of December 31, 2019 and 2018 were $10 million and $20 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability. See "Rockport Lease" section of Note 13 for additional information.

Significant Equity Method Investments in Unconsolidated Entities

For a discussion of the equity method of accounting, see the "Equity Investment in Unconsolidated Entities" section of Note 1.

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 December 31, 2019, AEP's investment in the five joint venture wind farms was $394 million. The investment includes amounts recognized in AOCI related to interest rate cash flow hedges. The investment is comprised of a historical investment of $420 million plus a basis difference of $(18) million. AEP's equity earnings associated with the five joint venture wind farms was a loss of $4 million for the year ended December 31, 2019. AEP recognized $27 million of PTC attributable to the joint venture wind farms for the year ended December 31, 2019, 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 held 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 December 31, 2019 and 2018, AEP’s investment in ETT was $695 million and $666 million, respectively. AEP’s equity earnings associated with ETT were $66 million, $62 million and $82 million for the years ended December 31, 2019, 2018 and 2017 respectively.

18. PROPERTY, PLANT AND EQUIPMENT

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

Property, Plant and Equipment is shown functionally on the face of the balance sheets. The following tables include the total plant balances as of December 31, 2019 and 2018:

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Regulated Property, Plant and Equipment								
Generation	$ 21,323.5 (a)	$ —	$ —	$ 6,563.7	$ 5,099.7	$ —	$ 1,574.6	$ 4,691.4 (a)
Transmission	24,763.4	4,466.5	8,137.9	3,584.1	1,641.8	2,686.3	948.5	2,056.5
Distribution	22,440.8	4,215.2	—	4,201.7	2,437.6	5,323.5	2,684.8	2,270.7
Other	4,369.6	803.4	268.2	542.0	590.9	754.7	337.2	520.6
CWIP	4,261.2 (a)	763.9	1,485.7	593.4	382.3	394.4	133.4	210.1 (a)
Less: Accumulated Depreciation	18,778.1	1,465.0	402.3	4,425.6	3,281.4	2,261.7	1,579.9	2,766.2
Total Regulated Property, Plant and Equipment - Net	58,380.4	8,784.0	9,489.5	11,059.3	6,870.9	6,897.2	4,098.6	6,983.1
Nonregulated Property, Plant and Equipment - Net	1,757.7	61.1	1.4	22.6	28.8	9.8	4.7	112.1
Total Property, Plant and Equipment - Net	$ 60,138.1	$ 8,845.1	$ 9,490.9	$ 11,081.9	$ 6,899.7	$ 6,907.0	$ 4,103.3	$ 7,095.2

December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Regulated Property, Plant and Equipment								
Generation	$ 20,989.1 (a)	$ —	$ —	$ 6,509.6	$ 4,887.2	$ —	$ 1,577.0	$ 4,672.6 (a)
Transmission	21,500.5	3,683.6	6,515.8	3,317.7	1,576.8	2,544.3	892.3	1,866.9
Distribution	21,192.8	4,043.2	—	3,989.4	2,249.7	4,942.3	2,572.8	2,178.6
Other	3,770.8	724.6	172.6	457.4	543.1	563.7	298.1	485.2
CWIP	4,352.6 (a)	836.0	1,578.3	490.2	465.3	432.1	94.0	194.7 (a)
Less: Accumulated Depreciation	17,743.1	1,431.2	271.9	4,118.9	3,139.4	2,217.7	1,472.1	2,633.5
Total Regulated Property, Plant and Equipment - Net	54,062.7	7,856.2	7,994.8	10,645.4	6,582.7	6,264.7	3,962.1	6,764.5
Nonregulated Property, Plant and Equipment - Net	1,036.4	135.6	1.4	22.9	28.5	10.2	4.6	107.3
Total Property, Plant and Equipment - Net	$ 55,099.1	$ 7,991.8	$ 7,996.2	$ 10,668.3	$ 6,611.2	$ 6,274.9	$ 3,966.7	$ 6,871.8

(a) AEP and SWEPCo's regulated generation and regulated CWIP include amounts related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

Depreciation, Depletion and Amortization

The Registrants provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide total regulated annual composite depreciation rates and depreciable lives for the Registrants:

AEP

Functional Class of Property	2019 Annual Composite Depreciation Rate Ranges	2019 Depreciable Life Ranges (in years)	2018 Annual Composite Depreciation Rate Ranges	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate Ranges	2017 Depreciable Life Ranges (in years)
Generation	2.5% - 5.5%	20 - 132	2.4% - 4.0%	20 - 132	2.3% - 3.7%	20 - 132
Transmission	1.8% - 2.6%	15 - 81	1.6% - 2.7%	15 - 81	1.6% - 2.7%	15 - 100
Distribution	2.7% - 3.7%	7 - 78	2.7% - 3.6%	7 - 78	2.7% - 3.7%	5 - 156
Other	2.6% - 9.5%	5 - 75	2.3% - 9.8%	5 - 75	2.3% - 9.2%	5 - 84

AEP Texas

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)
Transmission	1.8%	45 - 81	1.7%	45 - 81	1.7%	45 - 81
Distribution	3.5%	7 - 70	3.6%	7 - 70	3.6%	7 - 70
Other	6.3%	5 - 50	6.0%	5 - 50	8.7%	5 - 50

AEPTCo

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)
Transmission	2.0%	24 - 75	1.9%	20 - 75	1.7%	20 - 100
Other	5.8%	5 - 64	5.6%	5 - 64	6.7%	5 - 84

APCo

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)
Generation	3.2%	35 - 118	3.1%	35 - 112	3.1%	35 - 112
Transmission	1.8%	15 - 71	1.6%	15 - 68	1.6%	15 - 68
Distribution	3.7%	12 - 57	3.6%	10 - 57	3.7%	10 - 57
Other	7.2%	5 - 55	7.4%	5 - 55	6.5%	5 - 55

I&M

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)
Generation	4.0%	20 - 132	3.4%	20 - 132	2.4%	20 - 132
Transmission	1.9%	50 - 73	1.8%	50 - 73	1.7%	50 - 75
Distribution	3.4%	9 - 75	3.1%	9 - 75	2.7%	10 - 70
Other	9.4%	5 - 50	8.9%	5 - 50	8.4%	5 - 45

OPCo

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)
Transmission	2.3%	39 - 60	2.3%	39 - 60	2.3%	39 - 60
Distribution	3.1%	14 - 65	3.0%	14 - 65	2.8%	5 - 57
Other	4.9%	5 - 50	6.3%	5 - 50	6.2%	5 - 50

PSO

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges
		(in years)		(in years)		(in years)
Generation	2.9%	35 - 75	2.9%	35 - 75	2.4%	35 - 85
Transmission	2.4%	45 - 75	2.3%	45 - 75	2.2%	45 - 100
Distribution	2.9%	15 - 78	2.9%	15 - 78	2.7%	27 - 156
Other	5.6%	5 - 64	6.3%	5 - 64	7.4%	5 - 84

SWEPCo

Functional Class of Property	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges
		(in years)		(in years)		(in years)
Generation	2.5%	40 - 70	2.4%	40 - 70	2.3%	40 - 70
Transmission	2.4%	50 - 73	2.2%	50 - 73	2.3%	50 - 73
Distribution	2.7%	25 - 70	2.7%	25 - 70	2.7%	25 - 70
Other	7.6%	5 - 55	8.0%	5 - 55	7.2%	5 - 55

The following table includes the nonregulated annual composite depreciation rate ranges and nonregulated depreciable life ranges for AEP and AEP Texas. Depreciation rate ranges and depreciable life ranges are not meaningful for nonregulated property of AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo for 2019, 2018 and 2017.

Functional Class of Property	2019 Annual Composite Depreciation Rate Ranges	2019 Depreciable Life Ranges	2018 Annual Composite Depreciation Rate Ranges	2018 Depreciable Life Ranges	2017 Annual Composite Depreciation Rate Ranges	2017 Depreciable Life Ranges
		(in years)		(in years)		(in years)
Generation	3.2% - 21.2%	15 - 59	3.4% - 22.3%	15 - 59	2.4% - 5.1%	15 - 66
Transmission	2.5%	30 - 40	2.4%	40	0.2%	40
Distribution	2.3%	40	2.3%	40	2.3%	40
Other	17.6%	5 - 50 (a)	16.3%	5 - 50 (a)	12.1%	5 - 50 (a)

(a) SWEPCo's nonregulated property, plant and equipment is depreciated using the straight-line method over a range of 3 to 20 years.

SWEPCo provides for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. SWEPCo uses either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. SWEPCo includes these costs in fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (Applies to all Registrants except AEPTCo)

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms, solar farms and certain coal mining facilities. I&M records ARO for the decommissioning of the Cook Plant. The Registrants have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrants plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrants abandon or cease the use of specific easements, which is not expected.

As of December 31, 2019 and 2018, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.73 billion and $1.66 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2019 and 2018, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $2.65 billion and $2.16 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2019 and 2018 aggregate carrying amounts of ARO by Registrant:

Company	ARO as of December 31, 2018	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2019
			(in millions)			
AEP (b)(c)(d)(e)	$ 2,355.5	$ 102.5	$ 12.0	$ (118.1)	$ 67.0	$ 2,418.9
AEP Texas (b)(e)	27.9	1.3	—	(0.2)	0.1	29.1
APCo (b)(e)	116.1	5.9	—	(17.6)	6.7	111.1
I&M (b)(c)(e)	1,681.3	67.4	—	(0.2)	0.1	1,748.6
OPCo (e)	1.8	0.1	—	(0.3)	0.2	1.8
PSO (b)(e)	46.9	3.1	—	(0.4)	2.6	52.2
SWEPCo (b)(d)(e)	206.8	10.3	—	(11.8)	6.9	212.2

Company	ARO as of December 31, 2017	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2018
			(in millions)			
AEP (b)(c)(d)(e)	$ 2,005.7	$ 93.7	$ 0.8	$ (87.0)	$ 342.3 (f)	$ 2,355.5
AEP Texas (b)(e)	26.7	1.2	—	(0.1)	0.1	27.9
APCo (b)(e)	125.0	6.6	—	(17.3)	1.8	116.1
I&M (b)(c)(e)	1,321.8	58.7	—	(0.2)	301.0 (f)	1,681.3
OPCo (e)	1.7	0.1	—	—	—	1.8
PSO (b)(e)	54.0	3.2	—	(0.4)	(9.9)	46.9
SWEPCo (b)(d)(e)	169.2	9.1	0.2	(11.7)	40.0	206.8

(a) Primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.73 billion and $1.66 billion as of December 31, 2019 and 2018, respectively.
(d) Includes ARO related to Sabine and DHLC.
(e) Includes ARO related to asbestos removal.
(f) Revision for Cook Plant related to a new third-party study, which impacted the ARO liability for changes of estimated cash flows and application of a new discount rate.

Allowance for Funds Used During Construction and Interest Capitalization

The Registrants' amounts of Allowance for Equity Funds Used During Construction are summarized in the following table:

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
AEP	$ 168.4	$ 132.5	$ 93.7
AEP Texas	15.2	20.0	6.8
AEPTCo	84.3	70.6	49.0
APCo	16.6	13.2	9.2
I&M	19.4	11.9	11.1
OPCo	18.2	9.8	6.4
PSO	2.7	0.4	0.5
SWEPCo	6.8	6.0	2.4

The Registrants' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

Company	Years Ended December 31, 2019	2018	2017
	(in millions)		
AEP	$ 88.7	$ 73.6	$ 48.6
AEP Texas	20.0	18.4	6.8
AEPTCo	32.2	26.1	20.2
APCo	9.3	8.4	5.3
I&M	8.9	7.4	6.7
OPCo	6.7	5.8	3.8
PSO	1.9	0.9	1.1
SWEPCo	4.0	4.8	2.1

Jointly-owned Electric Facilities (Applies to AEP, AEP Texas, I&M, PSO and SWEPCo)

The Registrants have electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. Each Registrant's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

			Registrant's Share as of December 31, 2019		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Conesville Generating Station, Unit 4 (a)(h)	Coal	83.5%	$ —	$ —	$ —
Dolet Hills Power Station, Unit 1 (f)	Lignite	40.2%	337.3	6.2	216.5
Flint Creek Generating Station, Unit 1 (g)	Coal	50.0%	374.3	3.4	101.1
Pirkey Generating Station, Unit 1 (g)	Lignite	85.9%	607.8	7.7	416.8
Oklaunion Power Station (e)	Coal	70.3%	106.6	0.1	91.7
Turk Generating Plant (g)	Coal	73.3%	1,593.3	1.7	225.8
Total			$ 3,019.3	$ 19.1	$ 1,051.9
AEP Texas					
Oklaunion Power Station (e)	Coal	54.7%	$ 351.7	$ —	$ 291.9
I&M					
Rockport Generating Plant (b)(c)(d)	Coal	50.0%	$ 1,114.2	$ 105.5	$ 586.2
PSO					
Oklaunion Power Station (e)	Coal	15.6%	$ 106.6	$ 0.1	$ 91.7
SWEPCo					
Dolet Hills Power Station, Unit 1 (f)	Lignite	40.2%	$ 337.3	$ 6.2	$ 216.5
Flint Creek Generating Station, Unit 1 (g)	Coal	50.0%	374.3	3.4	101.1
Pirkey Generating Station, Unit 1 (g)	Lignite	85.9%	607.8	7.7	416.8
Turk Generating Plant (g)	Coal	73.3%	1,593.3	1.7	225.8
Total			$ 2,912.7	$ 19.0	$ 960.2

	Fuel Type	Percent of Ownership	Registrant's Share as of December 31, 2018		
			Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
			(in millions)		
AEP					
Conesville Generating Station, Unit 4 (a)(h)	Coal	83.5%	$ 16.4	$ 0.2	$ 2.4
Dolet Hills Power Station, Unit 1 (f)	Lignite	40.2%	336.2	5.1	209.6
Flint Creek Generating Station, Unit 1 (g)	Coal	50.0%	375.1	1.6	88.9
Pirkey Generating Station, Unit 1 (g)	Lignite	85.9%	591.3	16.6	418.0
Oklaunion Power Station (e)	Coal	70.3%	106.4	—	67.8
Turk Generating Plant (g)	Coal	73.3%	1,590.5	1.1	197.5
Total			$ 3,015.9	$ 24.6	$ 984.2
AEP Texas					
Oklaunion Power Station (e)	Coal	54.7%	$ 352.1	$ 0.2	$ 218.6
I&M					
Rockport Generating Plant (b)(c)(d)	Coal	50.0%	$ 1,108.7	$ 50.2	$ 514.1
PSO					
Oklaunion Power Station (e)	Coal	15.6%	$ 106.4	$ —	$ 67.8
SWEPCo					
Dolet Hills Power Station, Unit 1 (f)	Lignite	40.2%	$ 336.2	$ 5.1	$ 209.6
Flint Creek Generating Station, Unit 1 (g)	Coal	50.0%	375.1	1.6	88.9
Pirkey Generating Station, Unit 1 (g)	Lignite	85.9%	591.3	16.6	418.0
Turk Generating Plant (g)	Coal	73.3%	1,590.5	1.1	197.5
Total			$ 2,893.1	$ 24.4	$ 914.0

(a) Operated by AGR.
(b) Operated by I&M.
(c) Amounts include I&M's 50% ownership of both Unit 1 and capital additions for Unit 2. Unit 2 is subject to an operating lease with a nonaffiliated company. See the "Rockport Lease" section of Note 13.
(d) AEGCo owns 50% of Unit 1 with I&M and 50% of capital additions for Unit 2.
(e) Operated by PSO, which owns 15.6%. Also jointly-owned (54.7%) by AEP Texas and various nonaffiliated companies.
(f) Operated by CLECO, a nonaffiliated company.
(g) Operated by SWEPCo.
(h) Conesville Generating Station, Unit 4 was impaired as of December 31, 2019. See the "Impairments" section of Note 7.

19. GOODWILL

The disclosure in this note applies to AEP only.

The changes in AEP's carrying amount of goodwill for the years ended December 31, 2019 and 2018 by operating segment are as follows:

	Corporate and Other	Generation & Marketing	AEP Consolidated
		(in millions)	
Balance as of December 31, 2017	$ 37.1	$ 15.4	$ 52.5
Impairment Losses	—	—	—
Balance as of December 31, 2018	37.1	15.4	52.5
Impairment Losses	—	—	—
Balance as of December 31, 2019	$ 37.1	$ 15.4	$ 52.5

In the fourth quarters of 2019 and 2018, annual impairment tests were performed. The fair values of the reporting units with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. AEP does not have any accumulated impairment on existing goodwill.

20. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The table below represents AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Year Ended December 31, 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	$ 3,643.7	$ 2,069.9	$ —	$ —	$ —	$ —	$ 5,713.6
Commercial Revenues	2,155.3	1,152.9	—	—	—	—	3,308.2
Industrial Revenues	2,179.0	429.1	—	—	—	(0.9)	2,607.2
Other Retail Revenues	179.1	43.8	—	—	—	—	222.9
Total Retail Revenues	8,157.1	3,695.7	—	—	—	(0.9)	11,851.9
Wholesale and Competitive Retail Revenues:							
Generation Revenues (b)	807.6	—	—	254.8	—	—	1,062.4
Transmission Revenues (a)	292.1	435.1	1,077.2	—	—	(825.0)	979.4
Renewable Generation Revenues (c)	—	—	—	57.3	—	—	57.3
Retail, Trading and Marketing Revenues (b)	—	—	—	1,480.7	—	(135.6)	1,345.1
Total Wholesale and Competitive Retail Revenues	1,099.7	435.1	1,077.2	1,792.8	—	(960.6)	3,444.2
Other Revenues from Contracts with Customers (c)	168.2	169.4	16.6	4.9	104.7	(147.1)	316.7
Total Revenues from Contracts with Customers	9,425.0	4,300.2	1,093.8	1,797.7	104.7	(1,108.6)	15,612.8
Other Revenues:							
Alternative Revenues (c)	(57.9)	32.3	(20.6)	—	—	(66.9)	(113.1)
Other Revenues (c)	—	150.0	—	59.9	(8.9)	(139.3)	61.7
Total Other Revenues	(57.9)	182.3	(20.6)	59.9	(8.9)	(206.2)	(51.4)
Total Revenues	$ 9,367.1	$ 4,482.5	$ 1,073.2	$ 1,857.6	$ 95.8	$ (1,314.8)	$ 15,561.4

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $794 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $136 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues.

	Year Ended December 31, 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	$ 3,751.8	$ 2,189.4	$ —	$ —	$ —	$ —	$ 5,941.2
Commercial Revenues	2,183.4	1,251.7	—	—	—	—	3,435.1
Industrial Revenues	2,212.8	512.5	—	—	—	—	2,725.3
Other Retail Revenues	183.5	42.7	—	—	—	—	226.2
Total Retail Revenues (a)	8,331.5	3,996.3	—	—	—	—	12,327.8
Wholesale and Competitive Retail Revenues:							
Generation Revenues (d)	899.8	—	—	423.7	—	(7.3) (e)	1,316.2
Transmission Revenues (b)	282.2	372.1	849.3	—	—	(737.1)	766.5
Renewable Generation Revenues (d)	—	—	—	50.8	—	—	50.8
Retail, Trading and Marketing Revenues (c)	—	—	—	1,422.9	—	(120.7)	1,302.2
Total Wholesale and Competitive Retail Revenues	1,182.0	372.1	849.3	1,897.4	—	(865.1)	3,435.7
Other Revenues from Contracts with Customers (d)	158.4	204.6	15.2	20.6	86.2	(32.0)	453.0
Total Revenues from Contracts with Customers	9,671.9	4,573.0	864.5	1,918.0	86.2	(897.1)	16,216.5
Other Revenues:							
Alternative Revenues (d)	(15.9)	(22.2)	(60.4)	—	—	52.7	(45.8)
Other Revenues (d)	(10.5)	102.3	—	22.3	8.9	(98.0) (e)	25.0
Total Other Revenues	(26.4)	80.1	(60.4)	22.3	8.9	(45.3)	(20.8)
Total Revenues	$ 9,645.5	$ 4,653.1	$ 804.1	$ 1,940.3	$ 95.1	$ (942.4)	$ 16,195.7

(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 AEP Transmission Holdco was $643 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $121 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.
(e) 2018 amounts have been revised to reflect the reclassification of $98 million of affiliated revenues between Generation Revenues and Other Revenues. This reclassification did not impact previously reported Total Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

The table below represents revenues from contracts with customers, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

	Year Ended December 31, 2019						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 571.5	$ —	$ 1,266.9	$ 730.0	$ 1,502.0	$ 650.2	$ 638.6
Commercial Revenues	411.5	—	559.9	494.2	738.5	388.5	485.4
Industrial Revenues	129.4	—	592.2	550.7	299.9	303.5	338.7
Other Retail Revenues	29.9	—	75.2	7.3	13.1	81.6	9.0
Total Retail Revenues	1,142.3	—	2,494.2	1,782.2	2,553.5	1,423.8	1,471.7
Wholesale Revenues:							
Generation Revenues (a)	—	—	251.5	402.4	—	39.5	194.7
Transmission Revenues (b)	379.2	1,025.5	103.6	25.1	56.0	27.5	106.7
Total Wholesale Revenues	379.2	1,025.5	355.1	427.5	56.0	67.0	301.4
Other Revenues from Contracts with Customers (c)	30.1	16.6	61.8	98.4	139.3	22.0	26.1
Total Revenues from Contracts with Customers	1,551.6	1,042.1	2,911.1	2,308.1	2,748.8	1,512.8	1,799.2
Other Revenues:							
Alternative Revenues (d)	0.6	(20.7)	13.6	(1.4)	31.7	(31.0)	(48.3)
Other Revenues (d)	157.1	—	—	—	17.1	—	—
Total Other Revenues	157.7	(20.7)	13.6	(1.4)	48.8	(31.0)	(48.3)
Total Revenues	$ 1,709.3	$ 1,021.4	$ 2,924.7	$ 2,306.7	$ 2,797.6	$ 1,481.8	$ 1,750.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $129 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $782 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $73 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.

	Year Ended December 31, 2018						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 578.9	$ —	$ 1,342.7	$ 730.0	$ 1,611.6	$ 659.0	$ 641.6
Commercial Revenues	414.7	—	580.4	485.0	835.6	394.2	483.9
Industrial Revenues	128.0	—	604.3	565.6	385.2	304.0	333.7
Other Retail Revenues	29.4	—	77.4	7.2	12.9	83.6	8.6
Total Retail Revenues (a)	1,151.0	—	2,604.8	1,787.8	2,845.3	1,440.8	1,467.8
Wholesale Revenues:							
Generation Revenues (b)	—	—	250.4	470.5	—	36.3	216.8
Transmission Revenues (c)	313.4	816.9	82.7	23.1	58.5	40.2	108.4
Total Wholesale Revenues	313.4	816.9	333.1	493.6	58.5	76.5	325.2
Other Revenues from Contracts with Customers (d)	28.6	15.1	55.3	99.6	176.1	19.1	24.0
Total Revenues from Contracts with Customers	1,493.0	832.0	2,993.2	2,381.0	3,079.9	1,536.4	1,817.0
Other Revenues:							
Alternative Revenues (e)	(1.3)	(55.9)	(23.8)	(2.1)	(20.8)	10.9	4.9
Other Revenues (e)	103.6	—	(1.9)	(8.2)	4.3	—	—
Total Other Revenues	102.3	(55.9)	(25.7)	(10.3)	(16.5)	10.9	4.9
Total Revenues	$ 1,595.3	$ 776.1	$ 2,967.5	$ 2,370.7	$ 3,063.4	$ 1,547.3	$ 1,821.9

(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 $134 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $646 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $70 million primarily relating to the barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(e) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

AEP has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for “Revenue from Contracts with Customers” allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity’s measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. AEP subsidiaries elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for AEP’s subsidiaries are summarized as follows:

Retail Revenues

AEP's subsidiaries within the Vertically Integrated Utilities and Transmission and Distribution Utilities segments have performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between AEP's subsidiaries and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice. Payments from Retail Electric Providers are due to AEP Texas within 35 days.

Wholesale Revenues - Generation

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments have performance obligations to sell electricity to wholesale customers from generation assets in PJM, SPP and ERCOT. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments also have performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales within the Vertically Integrated Utilities segment are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenues tables above.

APCo has a performance obligation to supply wholesale electricity to KGPCo through a PPA. The FERC regulates the cost-based wholesale power transactions between APCo and KGPCo. The purchased power agreement includes a component for the recovery of transmission costs under the FERC OATT. The transmission cost component of purchased power is cost-based and regulated by the Tennessee Regulatory Authority. APCo's performance obligation under the purchased power agreement is satisfied over time as KGPCo simultaneously receives and consumes the wholesale electricity. APCo's revenues from the purchased power agreement are presented within the Generation Revenues line in the disaggregated revenues tables above.

Wholesale Revenues - Transmission

AEP's subsidiaries within the Vertically Integrated Utilities, Transmission and Distribution Utilities and AEP Transmission Holdco segments have performance obligations to transmit electricity to wholesale customers through assets owned and operated by AEP subsidiaries. The performance obligation to provide transmission services in PJM, SPP and ERCOT encompass a time frame greater than a year, where the performance obligation within each RTO is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued monthly for SPP and ERCOT and weekly for PJM.

AEP subsidiaries within the PJM and SPP regions collect revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues tables above. AEP subsidiaries within the ERCOT region collect revenues through a combination of base rates and interim Transmission Costs of Services filings that are approved by the PUCT.

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the Transmission Agreement (TA), which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. PSO, SWEPCo and AEPSC are parties to the Transmission Coordination Agreement (TCA) by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. AEPTCo is a transmission owner within the PJM and SPP regions providing transmission services to affiliates in accordance with the OATT, TA and TCA. Affiliate revenues as a result of the respective TA and the TCA are reflected as Transmission Revenues in the disaggregated revenues tables above.

Marketing, Competitive Retail and Renewable Revenues

AEP's subsidiaries within the Generation & Marketing segment have performance obligations to deliver electricity to competitive retail and wholesale customers. Performance obligations for marketing, competitive retail and renewable offtake sales are satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are primarily variable as they are subject to customer's usage requirements; however, certain contracts mandate a delivery of a set quantity of electricity at a predetermined price, resulting in a fixed performance obligation.

Payment terms under marketing arrangements typically follow standard Edison Electric Institute and International Swaps and Derivatives Association terms, which call for payment in 20 days. Payments for competitive retail and offtake arrangements for renewable assets range from 15 to 60 days and are dependent on the product sold, location and the creditworthiness of customer. Invoices for marketing arrangements, competitive retail and offtake arrangements for renewable assets are issued monthly.

Fixed Performance Obligations

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of December 31, 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	2020	2021-2022	2023-2024	After 2024	Total
			(in millions)		
AEP	$ 953.0	$ 160.8	$ 160.6	$ 223.5	$ 1,497.9
AEP Texas	387.0	—	—	—	387.0
AEPTCo	1,090.7	—	—	—	1,090.7
APCo	158.0	32.3	23.2	11.6	225.1
I&M	29.6	8.8	8.8	4.4	51.6
OPCo	61.0	—	—	—	61.0
PSO	11.7	—	—	—	11.7
SWEPCo	30.4	—	—	—	30.4

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 any material contract assets as of December 31, 2019 and 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 any material contract liabilities as of December 31, 2019 and 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 December 31, 2019 and 2018. See "Securitized Accounts Receivable - AEP Credit" section of Note 14 for additional information.

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	Years Ended December 31, 2019	2018
	(in millions)	
AEPTCo	$ 65.9	$ 58.6
APCo	47.3	52.5
I&M	37.1	35.3
OPCo	33.9	46.1
PSO	9.7	12.4
SWEPCo	17.6	16.3

Contract Costs

Contract costs to obtain or fulfill a contract for AEP subsidiaries within the Generation & Marketing segment are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current and noncurrent assets on the Registrants' balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Other Operation on the Registrants' income statements. The Registrants did not have material contract costs as of December 31, 2019 and 2018.

21. UNAUDITED QUARTERLY FINANCIAL INFORMATION

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

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. The unaudited quarterly financial information for each Registrant is as follows:

Quarterly Periods Ended:	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
March 31, 2019								
Total Revenues	$ 4,056.8	$ 390.7	$ 243.5	$ 792.8	$ 614.3	$ 836.8	$ 332.8	$ 421.1
Operating Income	788.4	70.8	141.6	152.1	115.0	162.5	20.9	54.1
Net Income	574.1	34.4	104.3	133.7	98.9	128.0	6.2	29.0
Earnings Attributable to Common Shareholders	572.8	NA	NA	NA	NA	NA	NA	27.8
June 30, 2019								
Total Revenues	$ 3,573.6	$ 438.0	$ 266.9	$ 655.8	$ 543.1	$ 606.6	$ 348.1	$ 375.5
Operating Income	551.0	38.7	161.0	76.9	77.9	77.1	56.6	33.0
Net Income	459.1	80.6	136.0	55.5	60.3	50.6	41.9	7.3
Earnings Attributable to Common Shareholders	461.3	NA	NA	NA	NA	NA	NA	6.2
September 30, 2019								
Total Revenues	$ 4,315.0	$ 489.3	$ 259.7	$ 755.5	$ 611.1	$ 710.6	$ 493.0	$ 545.5
Operating Income	958.2	118.2	142.3	142.6	107.3	98.6	120.0	134.7
Net Income	733.9	77.0	107.6	104.3	88.8	69.1	100.3	111.3
Earnings Attributable to Common Shareholders	733.5	NA	NA	NA	NA	NA	NA	110.5
December 31, 2019								
Total Revenues	$ 3,616.0	$ 391.3	$ 251.3	$ 720.6	$ 538.2	$ 643.6	$ 307.9	$ 408.8
Operating Income	294.7	4.3	122.3	25.7	40.6	63.0	1.8	33.9
Net Income (Loss)	152.7	(13.7)	91.8	12.8	21.4	49.4	(10.8)	14.6
Earnings Attributable to Common Shareholders	153.5	NA	NA	NA	NA	NA	NA	14.1

Quarterly Periods Ended:	AEP		AEP Texas		AEPTCo		APCo		I&M		OPCo		PSO		SWEPCo
	(in millions)														
March 31, 2018															
Total Revenues	$	4,048.3	$	371.6	$	191.7	$	820.4	$	576.8	$	790.9	$	336.8	$ 419.4
Operating Income		706.0		81.8		111.1		193.0		97.4		117.3		3.9	41.6
Net Income (Loss)		456.7		46.8		84.1		125.5		64.2		79.6		(7.2)	13.4
Earnings Attributable to Common Shareholders		454.4		NA		NA		NA		NA		NA		NA	11.8
June 30, 2018															
Total Revenues	$	4,013.2	$	388.3	$	200.1	$	667.0	$	589.7	$	748.8	$	398.3	$ 457.1
Operating Income		757.0		86.2		110.5		132.6		117.4		104.4		57.2	70.5
Net Income		530.1		46.5		82.0		77.4		94.7		68.8		36.6	38.7
Earnings Attributable to Common Shareholders		528.4		NA		NA		NA		NA		NA		NA	37.6
September 30, 2018															
Total Revenues	$	4,333.1	$	433.4	$	194.4	$	762.0	$	629.7	$	778.3	$	481.4	$ 535.3
Operating Income		668.6		94.0		97.0		49.8		110.2		79.9		78.5	127.1
Net Income		579.7		57.8		78.1		87.1		72.7		88.7		60.4	89.6
Earnings Attributable to Common Shareholders		577.6		NA		NA		NA		NA		NA		NA	88.2
December 31, 2018															
Total Revenues	$	3,801.1	$	402.0	$	189.9	$	718.1	$	574.5	$	745.4	$	330.8	$ 410.1
Operating Income		551.1		84.3		91.5		108.1		52.2		118.2		2.9	38.5
Net Income (Loss)		364.8		60.2		71.7		77.8		29.7		88.4		(6.6)	10.5
Earnings Attributable to Common Shareholders		363.4		NA		NA		NA		NA		NA		NA	9.6

NA Not applicable.

AEP

The unaudited quarterly financial information relating to Common Shareholders is as follows:

	2019 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Earnings Attributable to AEP Common Shareholders (in millions)	$ 572.8	$ 461.3	$ 733.5	$ 153.5
Basic Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	1.16	0.93	1.49	0.31
Diluted Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	1.16	0.93	1.48	0.31

	2018 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
Earnings Attributable to AEP Common Shareholders (in millions)	$ 454.4	$ 528.4	$ 577.6	$ 363.4
Basic Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	0.92	1.07	1.17	0.74
Diluted Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	0.92	1.07	1.17	0.74

(a) Quarterly Earnings per Share amounts are intended to be stand-alone calculations and are not always additive to full-year amount due to rounding.

Exhibit 21

Subsidiaries of
American Electric Power Company, Inc.
As of December 31, 2019

Each company shown indented is a subsidiary of the company immediately above which is not indented to the same degree. Subsidiaries not indented are directly owned by American Electric Power Company, Inc.

Name of Company	Location of Incorporation
American Electric Power Service Corporation	New York
AEP Energy Supply LLC	Delaware
AEP Clean Energy Resources, LLC	Delaware
AEP Generation Resources Inc.	Delaware
AEP Renewables, LLC	Delaware
AEP Generating Company	Ohio
AEP Transmission Holding Company, LLC	Delaware
AEP Transmission Company, LLC	Delaware
AEP Indiana Michigan Transmission Company, Inc	Indiana
AEP Ohio Transmission Company, Inc	Ohio
AEP Oklahoma Transmission Company, Inc	Oklahoma
AEP West Virginia Transmission Company, Inc	West Virginia
AEP Texas Inc.	Delaware
AEP Texas Central Transition Funding II LLC	Delaware
AEP Texas Central Transition Funding III LLC	Delaware
AEP Texas North Generation Company LLC	Delaware
AEP Texas Restoration Funding, LLC	Delaware
Appalachian Power Company	Virginia
Appalachian Consumer Rate Relief Funding LLC	Delaware
Indiana Michigan Power Company	Indiana
Kentucky Power Company	Kentucky
Kingsport Power Company	Virginia
Ohio Power Company	Ohio
Ohio Valley Electric Corporation	Ohio
Indiana-Kentucky Electric Corporation	Indiana
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware
Wheeling Power Company	West Virginia

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-222068 and 333-221520) and on Form S-8 (Nos. 333-224973, 333-204557, 333-178044) of American Electric Power Company, Inc. of our report dated February 20, 2020 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in the 2019 Annual Report, which is incorporated by reference in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 20, 2020 relating to the financial statement schedules, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (Nos. 333-225325) of AEP Transmission Company, LLC of our report dated February 20, 2020 relating to the financial statements, which appears in the 2019 Annual Report, which is incorporated by reference in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 20, 2020 relating to the financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-230613) of AEP Texas Inc. of our report dated February 20, 2020 relating to the financial statements, which appears in the 2019 Annual Report, which is incorporated by reference in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-225103) of Indiana Michigan Power Company of our report dated February 20, 2020 relating to the financial statements, which appears in the 2019 Annual Report, which is incorporated by reference in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-230094) of Ohio Power Company of our report dated February 20, 2020 relating to the financial statements, which appears in the 2019 Annual Report, which is incorporated by reference in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-226856) of Southwestern Electric Power Company of our report dated February 20, 2020 relating to the financial statements, which appears in the 2019 Annual Report, which is incorporated by reference in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

Exhibit 24

POWER OF ATTORNEY

AMERICAN ELECTRIC POWER COMPANY, INC.

Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2019

The undersigned directors of AMERICAN ELECTRIC POWER COMPANY, INC., a New York corporation (the "Company"), do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2019, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 12th day of February, 2020.

/s/ Nicholas K. Akins Nicholas K. Akins	/s/ Sandra Beach Lin Sandra Beach Lin
/s/ David J. Anderson David J. Anderson	/s/ Margaret M. McCarthy Margaret M. McCarthy
/s/ J. Barnie Beasley, Jr. J. Barnie Beasley, Jr.	/s/ Richard C. Notebaert Richard C. Notebaert
/s/ Ralph D. Crosby, Jr. Ralph D. Crosby, Jr.	/s/ Lionell L. Nowell, III Lionel L. Nowell, III
/s/ Art A. Garcia Art A. Garica	/s/ Stephen S. Rasmussen Stephen S. Rasmussen
/s/ Linda A. Goodspeed Linda A. Goodspeed	/s/ Oliver G. Richard, III Oliver G. Richard, III
/s/ Thomas E. Hoaglin Thomas E. Hoaglin	/s/ Sara Martinez Tucker Sara Martinez Tucker

Exhibit 24

POWER OF ATTORNEY

AEP TRANSMISSION COMPANY, LLC

Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2019

The undersigned managers of AEP TRANSMISSION COMPANY, LLC, a Delaware limited liability company (the "Company"), do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2019, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2020.

/s/ Nicholas K. Akins Nicholas K. Akins	/s/ A. Wade Smith A.Wade Smith
/s/ David M. Feinberg David M. Feinberg	/s/ Brian X. Tierney Brian X. Tierney
/s/ Mark C. McCullough Mark C. McCullough	

Exhibit 24

POWER OF ATTORNEY

Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2019

The undersigned directors of the following companies (each respectively the "Company")

Company	State of Incorporation
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2019, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2020.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

Exhibit 24

POWER OF ATTORNEY
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2019

The undersigned directors of the following companies (each respectively the "Company")

Company	State of Incorporation
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2019, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2020.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

POWER OF ATTORNEY

INDIANA MICHIGAN POWER COMPANY

Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2019

The undersigned directors of INDIANA MICHIGAN POWER COMPANY, an Indiana corporation (the "Company"), do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2019, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 14th day of February, 2020.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Nicholas M. Elkins
Nicholas M. Elkins

/s/ David M. Feinberg
David M. Feinberg

/s/ David S. Isaacson
David S. Isaacson

/s/ Marc E. Lewis
Marc E. Lewis

/s/ David A. Lucas
David A. Lucas

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Carla E. Simpson
Carla E. Simpson

/s/ Toby L. Thomas
Toby L. Thomas

/s/ Brian X. Tierney
Brian X. Tierney

Exhibit 24

POWER OF ATTORNEY
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2019

The undersigned directors of the following companies (each respectively the "Company")

Company	State of Incorporation
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2019, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2020.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

Exhibit 24

POWER OF ATTORNEY
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2019

The undersigned directors of the following companies (each respectively the "Company")

Company	State of Incorporation
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2019, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2020.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

Exhibit 24

POWER OF ATTORNEY
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2019

The undersigned directors of the following companies (each respectively the "Company")

Company	**State of Incorporation**
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2019, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2020.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

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-K 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: February 20, 2020 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-K 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: February 20, 2020

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-K 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: February 20, 2020 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-K 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: February 20, 2020

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-K 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: February 20, 2020 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-K 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: February 20, 2020 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-K 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: February 20, 2020   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-K 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: February 20, 2020 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-K 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.

By:

Date: February 20, 2020

/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-K 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: February 20, 2020	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-K 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.

By:

Date: February 20, 2020

/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-K 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.

By:

Date: February 20, 2020

/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-K 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: February 20, 2020

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-K 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.

By:

Date: February 20, 2020

/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-K 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: February 20, 2020

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-K 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: February 20, 2020

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 Annual Report of American Electric Power Company, Inc. (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of AEP Transmission Company, LLC (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 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

February 20, 2020

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 Annual Report of AEP Texas Inc. (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of Appalachian Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of Indiana Michigan Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of Ohio Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of Public Service Company of Oklahoma (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 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

February 20, 2020

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 Annual Report of Southwestern Electric Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of American Electric Power Company, Inc. (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 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

February 20, 2020

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 Annual Report of AEP Transmission Company, LLC (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of AEP Texas Inc. (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 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

February 20, 2020

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 Annual Report of Appalachian Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of Indiana Michigan Power Company (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 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

February 20, 2020

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 Annual Report of Ohio Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of Public Service Company of Oklahoma (the "Company") on Form 10-K (the "Report") for the year ended December 31, 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

February 20, 2020

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 Annual Report of Southwestern Electric Power Company (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 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

February 20, 2020

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 December 31, 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 **	$	—
Number of Mining-related Fatalities		0

* References to sections under the Mine Act.

** DHLC received two non-S&S citations during the fourth quarter of 2019. Proposed assessments for those citations were not received in 2019.

There are currently no legal actions pending before the Federal Mine Safety and Health Review Commission.