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

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **September 30, 2020**
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	The NASDAQ Stock Market LLC
American Electric Power Company Inc.	6.125% Corporate Units	AEPPL	The NASDAQ Stock Market LLC
American Electric Power Company Inc.	6.125% Corporate Units	AEPPZ	The NASDAQ Stock Market LLC

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

Yes ☒ No ☐

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

Yes ☒ No ☐

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

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

Smaller reporting company ☐ Emerging growth company ☐

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

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

Smaller reporting company ☐ Emerging growth company ☐

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

☐

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

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

	Number of shares of common stock outstanding of the Registrants as of October 22, 2020
American Electric Power Company, Inc.	496,386,252
	($6.50 par value)
AEP Texas Inc.	100
	($0.01 par value)
AEP Transmission Company, LLC (a)	NA
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	3,680
	($18 par value)

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

NA Not applicable.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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September 30, 2020

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEP Wind Holdings LLC	Acquired in April 2019 as Sempra Renewables LLC, develops, owns and operates, or holds interests in, wind generation facilities in the United States.
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 Equity Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
AMI	Advanced Metering Infrastructure.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
APSC	Arkansas Public Service Commission.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for rate-making purposes.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
Cardinal Operating Company	A jointly-owned organization between AGR and a nonaffiliate. The nonaffiliate operates the three unit Cardinal Plant and wholly-owns Units 2 and 3.
CARES Act	Coronavirus Aid, Relief, and Economic Security Act signed into law in March 2020.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,288 MW nuclear plant owned by I&M.
COVID-19	Coronavirus 2019, a highly infectious respiratory disease. In March 2020, the World Health Organization declared COVID-19 a worldwide pandemic.
CSAPR	Cross-State Air Pollution Rule.
CWA	Clean Water Act.
CWIP	Construction Work in Progress.

Term	Meaning
DCC Fuel	DCC Fuel IX, DCC Fuel X, DCC Fuel XI, DCC Fuel XII, DCC Fuel XIII, DCC Fuel XIV and DCC XV, consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
Desert Sky	Desert Sky Wind Farm LLC, a 170 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas in which AEP owns a 100% interest.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo. DHLC is a non-consolidated VIE of SWEPCo.
DIR	Distribution Investment Rider.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
ENEC	Expanded Net Energy Cost.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
Equity Units	AEP's Equity Units issued in August 2020 and March 2019.
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.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
Global Settlement	In February 2017, the PUCO approved a settlement agreement filed by OPCo in December 2016 which resolved all remaining open issues on remand from the Supreme Court of Ohio in OPCo's 2009 - 2011 and June 2012 - May 2015 ESP filings. It also resolved all open issues in OPCo's 2009, 2014 and 2015 SEET filings and 2009, 2012 and 2013 Fuel Adjustment Clause Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
MISO	Midcontinent Independent System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NAAQS	National Ambient Air Quality Standards.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
North Central Wind Energy Facilities	A joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,485 MWs of wind generation.

Term	Meaning
NO_2	Nitrogen dioxide.
NO_x	Nitrogen oxide.
NPDES	National Pollutant Discharge Elimination System.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
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.
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.
PATH-WV	PATH West Virginia Transmission Company, LLC, a joint venture owned 50% by FirstEnergy and 50% by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PTC	Production Tax Credits.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Racine	A generation plant consisting of two hydroelectric generating units totaling 48 MWs located in Racine, Ohio and owned by AGR.
Reference Rate Reform	The global transition away from referencing the London Interbank Offered Rate and other interbank offered rates, and toward new reference rates that are more reliable and robust.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants:AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO an SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Restoration Funding	AEP Texas Restoration Funding LLC, a wholly-owned subsidiary of AEP Texas and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Texas primarily caused by Hurricane Harvey.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1In 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 VIE for AEP and SWEPCo.
Santa Rita East	Santa Rita East Wind Holdings, LLC, a consolidated VIE whose sole purpose is to own and operate a 302.4 MW wind generation facility in west Texas in which AEP owns a 75% interest.
SEC	United States Securities and Exchange Commission.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019, consists of 724 MWs of wind generation and battery assets in the United States.
SIP	State Implementation Plan.

Term	Meaning
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA).The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
Transition Funding	AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC wholly-owned subsidiaries of TCC and consolidated VIEs formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated VIE formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Trent	Trent Wind Farm LLC, a 156 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas in which AEP owns a 100% interest.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Part 1 – Item 2 Management's Discussion and Analysis of Financial Condition and Results of Operations" of this quarterly report, but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Changes in economic conditions, electric market demand and demographic patterns in AEP service territories.
- The impact of pandemics, including COVID-19, and any associated disruption of AEP's business operations due to impacts on economic or market conditions, electricity usage, employees, customers, service providers, vendors and suppliers.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Decreased demand for electricity.
- Weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs.
- The cost of fuel and its transportation, the creditworthiness and performance of fuel suppliers and transporters and the cost of storing and disposing of used fuel, including coal ash and SNF.
- The availability of fuel and necessary generation capacity and the performance of generation plants.
- The ability to recover fuel and other energy costs through regulated or competitive electric rates.
- The ability to build or acquire renewable generation, transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or PM and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including coal ash and nuclear fuel.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- The ability to constrain operation and maintenance costs.
- Prices and demand for power generated and sold at wholesale.
- Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.
- The ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within RTOs including ERCOT, PJM and SPP.
- Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- The impact of volatility in the capital markets on the value of the investments held by the pension, OPEB, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.

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

The forward-looking statements of the Registrants speak only as of the date of this report or as of the date they are made. The Registrants expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see "Risk Factors" in Part I of the 2019 Annual Report and in Part II of this report.

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

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

COVID-19

In March 2020, COVID-19 was declared a pandemic by the World Health Organization and the Centers for Disease Control and Prevention. Its rapid spread around the world and throughout the United States prompted many countries, including the United States, to institute restrictions on travel, public gatherings and certain business operations. These restrictions significantly disrupted economic activity in AEP's service territory and could reduce future demand for energy, particularly from commercial and industrial customers. Although AEP cannot predict the severity or duration of the impact of the COVID-19 pandemic, AEP currently anticipates a 2.7% reduction in weather-normalized retail sales volume in 2020 as compared to the prior year. For the nine months ended September 30, 2020, AEP experienced a reduction in weather-normalized retail sales volume of 3.0% as compared to the same period in the prior year primarily driven by a 7.0% decrease in the industrial customer class and a 4.9% decrease in the commercial customer class offset by an increase in demand of 2.6% from the residential customer class. The reduction in weather-normalized retail sales volume of 3.0% did not result in a significant decrease in the corresponding retail margins for the nine months ended 2020 as the increase in higher margin residential sales volumes partially offset the decreases in the industrial and commercial sales volumes. Furthermore, the rate design for certain industrial customers includes demand provisions designed to cover the fixed portion of utility costs minimizing the impact of the fluctuations in usage on revenues. AEP's load forecast is highly dependent on many factors including, but not limited to, the speed and strength of economic recovery and the extent and duration of the next wave of COVID-19 infection.If the severity of the economic disruption increases, AEP's future results of operations, financial condition, and cash flows could be further adversely impacted. See Customer Demand for additional information.

During the first quarter of 2020, AEP's electric operating companies informed both retail customers and state regulators that disconnections for non-payment were temporarily suspended. Shortly thereafter, AEP's state regulators also imposed temporary moratoria on customary disconnection practices. During the third and the fourth quarter of 2020, certain state regulators began to lift restrictions on disconnects. As of September 30, 2020, AEP resumed disconnections in its regulated jurisdictions with the exception of Virginia, West Virginia, Kentucky, Arkansas, Louisiana and Tennessee. AEP's electric operating companies continue to work with regulators and stakeholders in these states and management currently anticipates resuming customary disconnection practices in the fourth quarter of 2020. However, this timing could change if there is new legislation or other regulatory directives issued in the future. Continuing adverse economic conditions may result in the inability of customers to pay for electric service, which could affect revenue recognition and the collectability of accounts receivable. During the third quarter of 2020, the Registrants reviewed current collections experience with historical trends, specifically reviewing metrics such as cash collections, days sales outstanding, daily customer deposits, and aging summaries. In addition, the Registrants reviewed historical loss information generally comprised of a rolling 12-month average, in conjunction with a qualitative assessment of elements that impact the collectability of receivables, such as changes in economic factors, regulatory matters, industry trends, customer credit factors, payment plan options and other programs available to customers. Based on this review, the Registrants' accounts receivable aging was negatively impacted primarily due to the suspension of customer disconnects. However, as disconnect moratoriums ended or are approaching their end dates, AEP is proactively engaging with customers to collect payments or establish payment arrangements for outstanding balances. As of September 30, 2020, AEP currently does not expect the deterioration in aging to have a material adverse impact on the Registrants' allowance for uncollectible accounts based on considerations of the COVID-19 impacts and past trends during times of economic instability. Management continues to monitor developments affecting suspensions of disconnections and its impact on customer collections. Further deterioration in AEP's ability to collect from its customers could significantly impact AEP's future results of operations, financial conditions, and cash flows.

In May 2020, AEP Credit amended its receivables securitization agreement to increase the eligibility criteria related to aged receivable requirements for the participating affiliated utility subsidiaries in response to the COVID-19 pandemic.As of September 30, 2020, the affiliated utility subsidiaries are in compliance with all requirements under the agreement. To the extent that an affiliated utility subsidiary is deemed ineligible under the agreement, receivables would no longer be purchased by the bank conduits and the Registrants would need to rely on additional sources of funding for operation and working capital, which may adversely impact liquidity.

The Registrants have worked with their state commissions to achieve deferral authority for incremental expenses incurred due to COVID-19All of AEP's regulated jurisdictions have issued initial COVID-19 orders with the exception of Tennessee.If any costs related to COVID-19 are not recoverable, it could reduce future net income and cash flows and impact financial condition.

The effects of the continued COVID-19 pandemic and related government responses could also include extended disruptions to supply chains, reduced labor availability, reduced dispatch for certain generation assets and a prolonged reduction in economic activity. These effects could have a variety of adverse impacts to the Registrants, including their ability to operate their facilities. As of September 30, 2020, there were no material adverse impacts to the Registrants' operations and supplier contracts due to COVID-19.AEP will continue to monitor developments affecting facility operations and will take additional actions necessary in order to mitigate adverse impacts to the Registrants' future results of operations, financial condition, and cash flows.

In addition, the economic disruptions caused by COVID-19 could also adversely impact the impairment risks for certain long-lived assets, equity method investments and goodwill. AEP evaluated these impairment considerations and determined that no such impairments existed as of September 30, 2020.

Market volatility and reduction in collections coupled with longer collection periods due to the expansion of customer payment arrangements could reduce cash from operations and cause an adverse impact to liquidity. During the first nine months of 2020, AEP increased its liquidity position to mitigate the market risk and the collections risk due to COVID-19. During the first quarter of 2020, AEP entered into a $1 billion 364–day term loan to reduce reliance on commercial paper and help mitigate potential future liquidity risks. In addition, during the first nine months of 2020, AEP issued approximately $4.0 billion in long-term debt. As of September 30, 2020, AEP's available liquidity was $3.8 billion.Management believes the Registrants have adequate liquidity under existing credit facilities. In the first quarter of 2020, AEP shifted capital expenditures of $500 million out of 2020 into future periods to further mitigate adverse liquidity impacts. In the second quarter of 2020, AEP reinstated $100 million of capital expenditures back into 2020 that had previously been deferred. To the extent that future access to the capital markets or the cost of funding is adversely affected by COVID-19, future results of operations, financial condition, and cash flows may be adversely impacted.

In March 2020, the CARES Act was signed into law. The CARES Act includes tax relief provisions such as: (a) an Alternative Minimum Ta (AMT) Credit Refund, (b) a 5-year net operating losses (NOL) carryback from years 2018-2020 and (c) delayed payment of employer payroll taxes. In May 2020, the House passed the "Health and Economic Recovery Omnibus Emergency Solutions Act" (HEROES Act) pending decision by th Senate. If enacted, the HEROES Act would disallow NOL carrybacks to any tax year beginning before January 1, 2018. Pursuant to the CARE Act, AEP, APCo and OPCo requested and in July received a $20 million, $7 million and $9 million, respectively, refund of AMT creditIn the third quarter of 2020, AEP also requested a $95 million refund of taxes paid in 2014 under the 5-year NOL carryback provision of the CARES ActAEP carried back an NOL generated on the 2019 Federal income tax return at a 21% federal corporate income tax rate to the 2014 Federal income tax return at a 35% corporate income tax rate. As a result of the change in the corporate income tax rates between the two periods, AEP realized a tax benefit of $52 million, recorded discretely, primarily at the Generation & Marketing segment. On October 1, 2020, after AEP filed its request with the IRS, the House passed a revised version of the HEROES Act; which similar to the original legislation would disallow NOL carryback to years prior t 2018. Management will continue to monitor the potential impact of this legislation. The Registrants are currently deferring payments of the employer share of payroll taxes for the period March 27, 2020 through December 31, 2020 and will pay 50% of the obligation by December 31, 2021 and the remaining 50% by December 31, 2022. As of September 30, 2020, the Registrants have deferred $32 million of the employer share of payroll taxes and anticipate to defer approximately $50 million by December 31, 2020.

The Registrants are taking steps to mitigate the potential risks to customers, suppliers and employees posed by the spread of COVID-19.The Registrants have updated and implemented a company-wide pandemic plan to address specific aspects of COVID-19.This plan guides emergency response, business continuity, and the precautionary measures AEP is taking on behalf of its employees and the public. The Registrants have taken extra precautions for employees who work in the field and for employees who work in their facilities, and have work from home policies where appropriate. The Registrants will continue to monitor developments affecting both their workforce and customers, and will take additional precautions that management determines are necessary in order to mitigate the impacts. AEP continues to focus on providing safe, uninterrupted service to its customers, which includes the implementation of strong physical and cyber-security measures to ensure that its systems remain functional with a partially remote workforce. As of September 30, 2020, there has been no material adverse impact to the Registrants' business operations and customer service due to remote work. Management will continue to review and modify plans as conditions change. Despite efforts to manage these impacts to the Registrants, the ultimate impact of COVID-19 also depends on factors beyond management's knowledge or control, including the duration and severity of this outbreak as well as third-party actions taken to contain its spread and mitigate its public health effects. Therefore, management cannot estimate the potential future impact to financial position, results of operations and cash flows, but the impacts could be material.

Customer Demand

AEP's weather-normalized retail sales volumes for the third quarter of 2020 decreased by 2.6% from the third quarter of 2019. Weather-normalized residential sales increased by 3.8% in the third quarter of 2020 from the third quarter of 2019. AEP's third quarter 2020 industrial sales volumes decreased by 7.8% compared to the third quarter of 2019. The decline in industrial sales was spread across many industries. Weather-normalized commercial sales decreased 4.6% in the third quarter of 2020 from the third quarter of 2019.

AEP's weather-normalized retail sales volumes for the nine months ended September 30, 2020 decreased by 3.0% compared to the nine months ended September 30, 2019. Weather-normalized residential sales increased by 2.6% for the nine months ended September 30, 2020 compared to the nine months ended September 30, 2019. AEP's industrial sales volumes for the nine months ended September 30, 2020 decreased 7.0% compared to the nine months ended September 30, 2019. The decline in industrial sales was spread across many industries. Weather-normalized commercial sales decreased 4.9% for the nine months ended September 30, 2020 compared to the nine months ended September 30, 2019.

As a result of the impact of COVID-19, AEP revised its forecast for 2020 weather-normalized retail sales volumes in April 2020 and September 2020 from the forecast presented in the 2019 10-K. In 2020, AEP currently anticipates weather-normalized retail sales volumes will decrease by 2.7%. AEP expects industrial class sales volumes to decrease by 6.5% in 2020, while weather-normalized residential sales volumes are projected to increase by 3.1%. Finally, AEP currently projects weather-normalized commercial sales volumes to decrease by 4.8%.

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(a) Percentage change for the year ended December 31, 2019 as compared to the year ended December 31, 2018.
(b) As presented in the 2019 AEP 10-K: Forecasted percentage change for the year ending December 31, 2020 compared to the year ended December 31, 2019.
(c) Revised for the impact of COVID-19 in April 2020: Forecasted percentage change for the year ending December 31, 2020 compared to the year ended December 31, 2019.
(d) Revised for the impact of COVID-19 in September 2020: Forecasted percentage change for the year ending 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.

- *2017-2019 Virginia Triennial Review* - In March 2020, APCo submitted its 2017-2019 Virginia triennial earnings review filing and base rate case with the Virginia SCC as required by state law. APCo requested a $65 million annual increase in base rates based upon a proposed 9.9% ROE. 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 customersIn such case, the Virginia SCC could also lower APCo's Virginia retail base rates on a prospective basis. 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 the Virginia jurisdictional share of these plants was $93 million before cost of removal, including materials and supplies inventory and ARO balances. 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. As a result, management deems these costs to be substantially recovered by APCo during the triennial review period. Inclusive of the Virginia jurisdictional share of the $93 million expense associated with APCo's retired coal-fired generation assets, APCo calculated its 2017-2019 Virginia earnings for the triennial period to be below the authorized ROE range. In July 2020, a certain intervenor filed testimony asserting that APCo had a revenue surplus of $23 million for its filed rate year based upon the intervenor's recommended ROE of 8.75%. In addition, this intervenor submitted corrected testimony contending APCo's earned return for the Triennial period was 11.12%, which equates to a potential refund to customers of $34 million. See "2017-2019 Virginia Triennial Review" section of Note 4 for a full listing of proposed adjustments and disallowances by intervenors. In August and September 2020, the Virginia staff filed testimony supporting an annual APCo Virginia jurisdictional revenue deficiency of $17 million based upon an ROE of 8.73%. However, Virginia staff contends APCo's earned return for the triennial period was 9.55%, which is above the 9.42% midpoint of APCo's authorized ROE range.Based on Virginia law, a Virginia SCC order finding an earned ROE above the midpoint would prevent APCo from receiving a prospective increase in Virginia retail rates. In addition, the staff recommended that APCo: (a) reverse the pretax Virginia jurisdictional share of the $93 million expense recorded in December 2019 for its retired coal-fired generation assets and instead amortize the retired assets over a 10-year period beginning in 2015, (b) implement 2017 depreciation study rates effective January 2018 which would increase depreciation expense by $13 million and $15 million in 2018 and 2019, respectively, (c) implement 2019 depreciation study rates effective January 2020 which would increase depreciation expense by $18 million annually starting January 1, 2020 and (d) remove $9 million of major storm expenses and $12 million of coal combustion by-product expenses from the requested annual increase in base rates. APCo expects to receive an order in November 2020.

- *Hurricane Laura* - In August 2020, Hurricane Laura hit the coasts of Louisiana and Texas, causing power outages to more than 130,000 customers across SWEPCo's service territories. Prior to Hurricane Laura, SWEPCo did not have a catastrophe reserve or automatic deferral authority within any of its jurisdictions. In September 2020, the LPSC issued an order allowing Louisiana utilities, including SWEPCo, to establish a regulatory asset to track and defer expenses associated with Hurricane Laura. In October 2020, as part of the 2020 Texas Base Rate Case, SWEPCo requested deferral authority of incremental other operation and maintenance expensesSWEPCo is currently evaluating recovery options for the storm damage in its Arkansas jurisdiction. As of September 30, 2020, management estimates that SWEPCo has incurred incremental other operation and maintenance expenses of $69 million ($67 million of which has been deferred as a regulatory asset related to the Louisiana jurisdiction) and incremental capital expenditures of $31 million ($30 million related to the Louisiana jurisdiction).

- *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 PUCTIn January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme CourtIn the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court.In August 2020, the Texas Supreme Court granted SWEPCo's petition for review and oral arguments were scheduled for December 2020.As of September 30, 2020, the net book value of Turk Plant was $1.4 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 (HB 6) which offers incentives for power-generating facilities with zero or reduced carbon emissions was signed into law by the Ohio Governor. HB 6 phased out current energy efficiency including lost shared savings revenues of $26 million annually and renewable mandates no later than 2020 and after 2026, respectively. HB 6 also provided for the recovery of existing renewable energy contracts on a bypassable basis through 2032 and included 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. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of the Speaker of the Ohio House of Representatives, Larry Householder, four other individuals, and Generation Now, an entity registered as a 501(c)(4) social welfare organization, in connection with a racketeering conspiracy involving the adoption of HB 6. In light of the allegations in the indictment, proposed legislation has been introduced that would repeal HB 6. The outcome of the U.S. Attorney's Office investigation and its impact on HB 6 is not known. If the provisions of HB 6 were to be eliminated, it is unclear whether and in what form the Ohio General Assembly would pass new legislation addressing similar issues. In August 2020, an AEP shareholder filed a putative class action lawsuit against AEP and certain of its officers for alleged violations of securities laws. See Litigation Related to Ohio House Bill 6 section of Litigation below for additional information. 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, fully recover energy efficiency costs through 2020 or incurs significant costs defending against the class action lawsuit, it could reduce future net income and cash flows and impact financial condition.

- In April 2020, the Virginia Clean Economy Act was signed into law by the Virginia Governor and became effective in July 2020.The law includes the following requirements: (a) Virginia electric utilities to retire no later than 2045 all electric generating units located in Virginia that emit carbon as a by-product, (b) APCo to produce 100% of the company's power to serve Virginia customers from renewable sources by 2050 with increasing percentages of mandatory renewable energy sources each year and (c) Virginia electric utilities to achieve increasing annual energy efficiency savings from 2022-2025 using 2019 as the base year. This law also provides that if the Virginia SCC finds in any triennial review that revenue reductions related to energy efficiency programs approved and deployed since the utility's previous triennial review have caused the utility to earn more than 70 basis points below its authorized rate of return, the Virginia SCC shall order increases to the utility's rates necessary to recover such revenue reductions. If any of these costs are not recoverable, 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 2020. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase (Decrease)		Approved ROE	New Rates Effective
		(in millions)			
I&M	Michigan	$ 36.4	(a)	9.86%	February 2020
I&M	Indiana	77.4	(b)	9.7%	March 2020
AEP Texas	Texas	(40.0)		9.4%	June 2020

(a) In January 2020, the MPSC issued an order approving a stipulation and settlement agreement.See "2019 Michigan Base Rate Case" section of Note 4 Rate Matters in the 2019 Annual Report for additional information.

(b) Will be phased-in through an increase in base rates which includes: (a) an annual increase in base rates of $44 million effective March 2020 and (b) an annual increase in base rates of up to $77 million effective January 2021 based on the IURC-approved forecast of December 31, 2020 Indiana jurisdictional electric plant in service. A compliance filing will be made in January 2021 to adjust the final rate increase to reflect the lower of I&Ms actual or IURC-approved Indiana jurisdictional electric plant in service balance as of December 31, 2020. The order rejected I&M's proposed re-allocation of capacity costs related to the loss of a significant FERC wholesale contract, which will negatively impact I&M's annual pretax earnings by approximately $20 million starting June 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)			
APCo	Virginia	March 2020	$ 64.9		9.9%	8.73% - 8.75%
OPCo	Ohio	June 2020	42.3		10.15%	(a)
KPCo	Kentucky	June 2020	65.0		10%	8.93% - 9.25%
SWEPCo	Texas	October 2020	105.0	(b)	10.35%	(a)

(a) Awaiting procedural schedule.

(b) The request would move transmission and distribution interim revenues recovered through riders into base rates. Eliminating these riders would result in a net annual requested base rate increase of $90 million primarily due to increased investments.

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.

As of September 30, 2020, subsidiaries within AEP's Generation & Marketing segment had approximately 1,520 MWs of contracted renewable generation projects in-service. In addition, as of September 30, 2020, these subsidiaries had approximately 140 MWs of renewable generation projects under construction with total estimated capital costs of $243 million related to these projects.

Regulated Renewable Generation Facilities

In July 2019, PSO and SWEPCo submitted filings before their respective commissions for the approval to acquire the North Central Wind Energ Facilities, comprised of three Oklahoma wind facilities totaling 1,485 MWs, on a fixed cost turn-key basis at completion. PSO will own 45.5% and SWEPCo will own 54.5% of the project, which will cost approximately $2 billion. In May 2020, the IRS issued a notice extending the "Continuity Safe Harbor" deadlines for qualifying renewable energy projects that began construction in 2016 and 2017 by one year as many projects are facing supply chain and other project development delays caused by COVID-19.Under the May 2020 IRS notice, qualifying renewable energy projects that began construction in 2016 and 2017 and which are placed in-service by the end of 2021 and 2022, respectively, will satisfy the Continuity Safe Harbor. Provided that each facility satisfies the Continuity Safe Harbor, under the current IRS guidance, the 199 MW wind facility will qualify for 100% of the federal PTC, and the remaining two wind facilities, totaling 1,286 MWs, will qualify for 80% of the federal PTC. The 199 MW wind facility is targeted to be placed in-service and acquired in March 2021. The 287 MW wind facility is targeted to be placed in-service and acquired in December 2021 and the 999 MW wind facility is targeted to be placed in-service and acquired between December 2021 and April 2022. All three wind facilities are expected to satisfy the Continuity Safe Harbor.

In February 2020, the OCC approved PSO's settlement agreementIn May 2020, the APSC approved the settlement agreement as filed, with the exception that SWEPCo use its formula rate rider to recover its costs rather than the requested rider.Also in May 2020, the LPSC approved the settlement agreement as filed. Both the APSC and LPSC approved the flex-up option, agreeing to acquire the Texas portion, which the PUCT deniec in July 2020. Having regulatory approval and the IRS extension of the "Continuity Safe Harbor," PSO and SWEPCo are proceeding with the full 1,485 MW development of these three projects.

Hydroelectric Generation

Evaluating Sale of Hydroelectric Generation

In March 2020, management placed 10 hydroelectric generation plants under study for a potential sale. In April 2020, the Virginia Clean Economy Act was signed into law by the Virginia Governor. The new law will provide renewable credits to APCo for its existing hydroelectric generation plants.As a result of the new law, management removed the three APCo hydroelectric generation plants (London, Marmet and Winfield) from the list of plants identified for potential sale. The table below shows the net book value of each plant, including CWIP and materials and supplies, before cost of removal of the remaining plants included in the study.

Owner	Plant Name	Units	State	Net Book Value as of September 30, 2020		Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
				(in millions)			
AGR	Racine	2	OH	$	44.7	48	1982
I&M	Berrien Springs	12	MI		6.2	6	1908
I&M	Buchanan	10	MI		4.3	3	1919
I&M	Constantine	4	MI		2.3	1	1921
I&M	Elkhart	3	IN		5.2	3	1913
I&M	Mottville	4	MI		2.7	2	1923
I&M	Twin Branch Hydro	8	IN		5.7	5	1904
	Total			$	71.1	68	

If management decides to proceed with the sale of these plants, FERC approval would be required.In addition, for all plants, except for Racine, state commission approval would be required. Management currently estimates that any potential sale agreements for these plants would not be entered into until late 2020 at the earliest. There is no assurance that management will be able to sell any of these plants.

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.DHLC provides 100% of the fuel supply to Dolet Hills Power StationAfter careful consideration of current economic conditions, and particularly for the benefit of their customers, management of SWEPCo and CLECO determined DHLC would not proceed developing additional Oxbow Lignite Company (Oxbow) mining areas for future lignite extraction and ceased extraction of lignite at the mine in May 2020. Based on these actions, management revised the estimated useful life of DHLC's and Oxbow's assets to coincide with the date at which extraction was discontinued in the second quarter of 2020 and the date at which delivery of lignite is expected to cease in September 2021. Management also revised the useful life of the Dolet Hills Power Station to 2021 based on the remaining estimated fuel supply available for continued seasonal operation. In March 2020, primarily due to the revision in the useful life of DHLC, SWEPCo recorded a revision to increase estimated ARO liabilities by $21 million. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining.

The Dolet Hills Power Station costs are recoverable by SWEPCo through base ratesSWEPCo's share of the net investment in the Dolet Hills Power Station is $153 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 clausesUnder the Lignite Mining Agreement, DHLC bills SWEPCo its proportionate share of incurred lignite extraction and associated mining-related costs as fuel is deliveredAs of September 30, 2020, DHLC has unbilled lignite inventory and fixed costs of $36 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. In 2009, SWEPCo acquired interests in 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 costsAs of September 30, 2020, Oxbow has unbilled fixed costs of $10 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power StationDHLC and Oxbow have billed SWEPCo $111 million for lignite deliveries from April 2020 through September 2020, which primarily includes accelerated depreciation and amortization of fixed costs. 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.

In October 2020, SWEPCo filed a request with the LPSC for recovery of the Louisiana share of these additional fuel costsSWEPCo's filing proposes to defer $36 million of fuel costs in 2021 and recover the deferral plus carrying costs over five years beginning in 2022.

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

FERC Transmission ROE Methodology

Management continues to monitor FERC's 2019 Notice of Inquiry regarding base ROE policy, FERC's 2020 Notice of Proposed Rulemaking regarding transmission incentives policy, and various other matters pending before FERC with the potential to affect FERC transmission ROE methodology.

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.In the second quarter of 2020, FERC Order 569A determined the base ROE for MISO's transmission owning members, including AEP's MISO transmission-owning subsidiaries, should be 10.02% (10.52% inclusive of the RTO incentive adder of 0.5%).

If FERC makes any changes to its ROE and incentive policies, they would be applied, as applicable, to AEP's PJM, SPP and MISO transmissic 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 5 – Commitments, Guarantees and Contingencies for additional information.

Rockport Plant Litigation

In 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering, refueling or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

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

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

Thereafter, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree. The district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. The consent decree was modified based on an agreement among the parties in July 2019. The district court's stay of the lease litigation expired in August 2020. Upon expiration of the stay, plaintiffs filed a motion for partial summary judgment, arguing that the consent decree violates the facility lease and the participation agreement and requesting that the district court enter a judgment for the plaintiffs on their breach of contract claim. AEP's memorandum in opposition was filed in October 2020. All deadlines, including discovery, are stayed, pending resolution of the motion. 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. In July 2020, plaintiffs amended the complaint to add three new patents. The amended complaint seeks injunctive relief and damages. The case is scheduled for trial in January 2023. 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; 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. The denial of those claims was appealed to the AEP System Retirement Plan Appeal Committee and the Committee upheld the denial of claims. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Litigation Related to Ohio House Bill 6

In August 2020, an AEP shareholder filed a putative class action lawsuit in the United States District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. The complaint alleges misrepresentations or omissions by AEP regarding: (a) its alleged participation in public corruption with respect to the passage of Ohio House Bill 6, (b) its regulatory, legislative and lobbying activities in Ohio and (c) its clean energy strategy. The complaint seeks monetary damages among other forms of relief. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP has a substantial capital investment program and incurs additional operational costs to comply with environmental control requirements. Additional investments and operational changes will be made in response to existing and anticipated requirements to reduce emissions from fossil generation and in response to rules governing the beneficial use and disposal of coal combustion by-products, clean water and renewal permits for certain water discharges.

AEP is engaged in litigation about environmental issues, was notified of potential responsibility for the clean-up of contaminated sites and incurred costs for disposal of SNF and future decommissioning of the nuclear units. AEP, along with other parties, challenged some of the Federal EPA requirements. Management is engaged in the development of possible future requirements including the items discussed below. Management believes that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

AEP will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If AEP cannot recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed below will have a material impact on AEP System generating units. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of September 30, 2020, the AEP System had generating capacity of approximately 24,300 MWs, of which approximately 12,100 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.

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 (SCR) technology at Rockport Plant, Unit 2 until June 2020Construction of the SCR technology was completed by June 1, 2020, testing was conducted, and the unit was released for dispatch on June 5, 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 (DSI) 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 reviewed the existing standards for NO_2 and SO_2 in 2018 and 2019, respectively, and decided to retain the standards without change. Implementation of these standards is underway. The Federal EPA is currently reviewing the existing standards for PM, last revised in 2012, and ozone, last revised in 2015. A proposed rule to retain the existing PM standards was released in April 2020. A proposed rule to retain the existing standards for ozone was released in August 2020.

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 certain 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. The Federal EPA finalized the intrastate trading program in July 2020. 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. In April 2020, the Federal EPA released a final rule adopting the conclusions set forth in the proposal and retaining the existing MATS standards. The rule has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit.

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. Information collection and rulemaking activities are underway in several states. 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. In April 2020, Virginia enacted clean energy legislation to allow the state to participate in the Regional Greenhouse Gas Initiative, require the retirement of all fossil-fueled generation by 2045 and require 100% renewable energy to be provided to Virginia customers by 2050. 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 two 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 final rule was published in August 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. In April 2020, the Supreme Court issued an opinion remanding one of these cases to the Ninth Circuit based on its determination that discharges from an injection well that make their way to the Pacific Ocean through ground water may require a permit if the distance traveled through ground water, length of time to reach the surface water and other factors make it "functionally equivalent" to a direct discharge from a point source. The second case was also remanded to the lower court. Prior to the Supreme Court's decision, 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 these developments on AEP's facilities.

In August 2020, the Federal EPA revised the CCR rule to include a requirement that unlined CCR storage ponds cease operations and initiate closure by April 11, 2021. The revised rule provides two options that allow facilities to extend the date by which they must cease receipt of coal ash and close the ponds. The deadline for seeking an extension under either option is November 30, 2020.

The first option provides an extension to cease receipt of CCR no later than October 15, 2023 for most units, and October 15, 2024 for a narrow subset of units; however, the Federal EPA's grant of such an extension will be based upon a satisfactory demonstration of the need for additional time to develop alternative ash disposal capacity and will be limited to the soonest timeframe technically feasible to cease receipt of CCR. Additionally, each request must undergo formal review, including public comments, and be approved by the Federal EPA.

The second option is a retirement option, which provides a generating facility an extended operating time without developing alternative CCR disposal. Under the retirement option, a generating facility would have until October 17, 2023 to cease operation and to close CCR storage ponds 40 acres or less in size, or through October 17, 2028 for facilities with CCR storage ponds greater than 40 acres in size.

Because AEP currently uses surface impoundments and landfills to manage CCR materials at generating facilities, significant costs may be incurred to upgrade or close and replace these existing facilities and conduct any required remedial actions. Management is evaluating various compliance options. Under the retirement option above, AEP may need to recover remaining depreciation and estimated closure costs associated with retiring plants over a shorter period. If AEP cannot ultimately recover the costs of environmental compliance and/or the remaining depreciation and estimated closure costs associated with retiring plants in a timely manner, it would reduce future net income and cash flows and impact financial condition.

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 March 2020, Virginia's Governor signed House Bill 443 (HB 443), effective July 2020, requiring APCo to close certain ash disposal units at the retired Glen Lyn Station by removal of all coal combustion material. As a result, in June 2020, APCo recorded a $199 million revision to increase estimated Glen Lyn Station ash disposal ARO liabilities. The closure is required to be completed within 15 years from the start of the excavation process. HB 443 provides for the recovery of all costs associated with closure by removal through the Virginia environmental rate adjustment clause (E-RAC). APCo may begin recovering these costs through the E-RAC beginning July 1, 2022. APCo is permitted to record carrying costs on the unrecovered balance of closure costs at a weighted average cost of capital approved by the Virginia SCC. HB 443 also allows any closure costs allocated to non-Virginia jurisdictional customers, but not collected from such non-Virginia jurisdictional customers, to be recovered from Virginia jurisdictional customers through the E-RAC.

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 participate in rulemaking activities and make adjustments based on new federal and state requirements affecting its ash disposal units.

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. AEP facilities that have had their wastewater discharge permits renewed have been asked to monitor intake flows or to enhance monitoring practices to assure the current technology is being properly managed to ensure compliance with this rule.

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. A final rule was signed by the Federal EPA in August 2020 and was published in October 2020. The final rule establishes additional options for reusing and discharging small volumes of bottom ash transport water, provides an exception for retiring units, and extends the compliance deadline to a date as soon as possible beginning one year after the rule was published but no later than December 2025. 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 for FGD wastewater and bottom ash transport water.

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. The final replacement rule was published in the Federal Register in April 2020 and became effective in June 2020. The final rule limits the scope of CWA jurisdiction to four categories of waters, and clarifies exclusions for ground water, ephemeral streams, artificial ponds and waste treatment systems. Challenges to the final rule and requests for a preliminary injunction have been brought by states and other groups in multiple U.S. District Courts. At this time, none of the jurisdictions in which AEP operates are impacted by a stay. Management is monitoring these various proceedings but is unable to predict the actions of the various courts.

In April 2020, the U.S. District Court for the District of Montana issued a decision vacating the U.S. Army Corps of Engineers' (Corps) General Nationwide Permit 12 (NWP 12), which provides standard conditions governing linear utility projects in streams, wetlands and other waters of the United States having minimal adverse environmental impacts. The Court found that in reissuing NWP 12 in 2017, the Corps failed to comply with Section 7 of the Endangered Species Act (ESA), which requires the Corps to consult with the U.S. Fish and Wildlife Service regarding potential impacts on endangered species. The Court remanded the permit back to the Corps to complete its ESA consultation, and also enjoined the Corps from authorizing any dredge or fill activities under NWP 12 pending completion of the consultation process. The Department of Justice filed a motion to stay the injunction and tailor the remedy imposed by the Court. In May 2020, the Court revised its order lifting the injunction for non-oil and gas pipeline construction activities and routine maintenance, inspection and repair activities on existing NWP 12 projects. The Department of Justice appealed the Court's decision to the Court of Appeals for the Ninth Circuit and moved for stay pending appeal, which was denied. In June 2020, the Department of Justice submitted an application to the U.S. Supreme Court requesting a stay of the District Court's Order, and the Court granted the request with respect to all oil and gas pipelines except the Keystone Pipeline. Management is monitoring the litigation and evaluating other permitting alternatives, but is currently unable to predict the impact of future proceedings on current and planned projects.

In September 2020, the Corps issued for public comment the proposed renewal of all General Nationwide Permits. As part of that proposal the Corps has narrowed the focus of NWP 12 to only oil and natural gas pipeline activities. The Corps is proposing two new Nationwide Permits governing electric utility line and telecommunications activities, and other utility lines (e.g., conveyance of potable water, sewage, other substances), respectively. Management is currently assessing impacts of the proposal on current and planned projects.

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 standard service offer customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Vertically Integrated Utilities	$ 393.5	$ 437.6	$ 894.7	$ 917.7
Transmission and Distribution Utilities	147.4	133.7	403.1	421.6
AEP Transmission Holdco	138.3	126.1	370.4	404.8
Generation & Marketing	116.7	90.0	211.0	139.5
Corporate and Other	(47.3)	(53.9)	(114.6)	(116.0)
Earnings Attributable to AEP Common Shareholders	$ 748.6	$ 733.5	$ 1,764.6	$ 1,767.6

AEP CONSOLIDATED

Third Quarter of 2020 Compared to Third Quarter of 2019

Earnings Attributable to AEP Common Shareholders increased from $734 million in 2019 to $749 million in 2020 to primarily due to:

- Favorable rate proceedings in AEP's various jurisdictions.
- A planned decrease in Other Operation and Maintenance expenses.
- The recognition of a discrete tax adjustment in 2020 which was attributable to the 5-year net operating loss carryback provision of the CARES Act.

These increases were partially offset by:

- A decrease in weather-related usage.
- A one-time reversal of a regulatory provision in 2019.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Earnings Attributable to AEP Common Shareholders decreased from $1,768 million in 2019 to $1,765 million in 2020 primarily due to:

- A decrease in weather-related usage.
- A one-time reversal of a regulatory provision in 2019.

These decreases were partially offset by:

- Favorable rate proceedings in AEP's various jurisdictions.
- A planned decrease in Other Operation and Maintenance expenses.
- The recognition of a discrete tax adjustment in 2020 which was attributable to the 5-year net operating loss carryback provision of the CARES Act.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
	(in millions)			
Revenues	$ 2,434.8	$ 2,645.5	$ 6,753.5	$ 7,172.6
Fuel and Purchased Electricity	693.7	874.2	1,947.0	2,430.2
Gross Margin	1,741.1	1,771.3	4,806.5	4,742.4
Other Operation and Maintenance	715.9	742.9	2,031.8	2,117.1
Depreciation and Amortization	398.8	364.3	1,173.8	1,079.6
Taxes Other Than Income Taxes	121.0	117.9	355.6	347.1
Operating Income	505.4	546.2	1,245.3	1,198.6
Other Income (Expense)	(0.7)	0.9	2.3	4.4
Allowance for Equity Funds Used During Construction	15.9	12.2	33.1	38.9
Non-Service Cost Components of Net Periodic Benefit Cost	16.9	17.0	50.9	50.8
Interest Expense	(140.2)	(140.6)	(426.5)	(422.6)
Income Before Income Tax Expense (Benefit) and Equity Earnings	397.3	435.7	905.1	870.1
Income Tax Expense (Benefit)	3.8	(1.9)	10.5	(48.4)
Equity Earnings of Unconsolidated Subsidiary	0.7	0.8	2.2	2.3
Net Income	394.2	438.4	896.8	920.8
Net Income Attributable to Noncontrolling Interests	0.7	0.8	2.1	3.1
Earnings Attributable to AEP Common Shareholders	$ 393.5	$ 437.6	$ 894.7	$ 917.7

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
	(in millions of KWhs)			
Retail:				
Residential	9,066	9,254	24,304	24,785
Commercial	6,257	6,840	16,773	18,183
Industrial	8,161	9,123	24,335	26,533
Miscellaneous	595	641	1,636	1,734
Total Retail	24,079	25,858	67,048	71,235
Wholesale (a)	4,574	5,864	13,116	16,494
Total KWhs	28,653	31,722	80,164	87,729

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

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in degree days)			
Eastern Region				
Actual – Heating (a)	3	—	1,456	1,670
Normal – Heating (b)	4	5	1,752	1,742
Actual – Cooling (c)	867	937	1,204	1,316
Normal – Cooling (b)	739	732	1,081	1,070
Western Region				
Actual – Heating (a)	1	—	699	967
Normal – Heating (b)	1	1	902	902
Actual – Cooling (c)	1,291	1,572	2,015	2,234
Normal – Cooling (b)	1,416	1,402	2,144	2,129

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

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Third Quarter of 2019	$	437.6
Changes in Gross Margin:		
Retail Margins		(14.3)
Margins from Off-system Sales		(5.5)
Transmission Revenues		(3.1)
Other Revenues		(7.3)
Total Change in Gross Margin		(30.2)
Changes in Expenses and Other:		
Other Operation and Maintenance		27.0
Depreciation and Amortization		(34.5)
Taxes Other Than Income Taxes		(3.1)
Other Income		(1.6)
Allowance for Equity Funds Used During Construction		3.7
Non-Service Cost Components of Net Periodic Pension Cost		(0.1)
Interest Expense		0.4
Total Change in Expenses and Other		(8.2)
Income Tax Expense		(5.7)
Equity Earnings of Unconsolidated Subsidiary		(0.1)
Net Income Attributable to Noncontrolling Interests		0.1
Third Quarter of 2020	$	393.5

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

- **Retail Margins** decreased $14 million primarily due to the following:
  - A $50 million decrease in weather-related usage primarily in the western region and primarily in the residential class.
  - A $24 million decrease in weather-normalized margins for wholesale customers, including the loss of a significant wholesale contract at I&M.
  - A $4 million decrease in revenue from rate riders at PSO. This decrease was partially offset in other expense items below.
  - A $3 million decrease in weather-normalized retail margins driven by a $42 million decrease in the commercial and industrial customer classes partially offset by a $41 million increase in the residential customer class.

  These decreases were partially offset by:
  - The effect of rate proceedings in AEP's service territories which included:
    - A $38 million increase at I&M primarily due to the Indiana and Michigan base rate cases and an overall increase in revenue from rate riders. This increase was partially offset in other expense items below.
    - A $14 million increase at SWEPCo primarily due to a base rate revenue increase in Arkansas.
  - A $10 million increase in deferred fuel at APCo and WPCo primarily due to the timing of recoverable PJM expenses.This increase was offset in other expense items below.
  - A $5 million increase at APCo and WPCo due to the WVPSC's approval of the Mitchell Plant surcharge effective January 2020.

- **Margins from Off-system Sales** decreased $6 million due to weaker market prices for energy in the RTOs which caused a decrease in sales volume and margins and the historical merchant portion of WPCo's Mitchell Plant moving to retail rates beginning in January 2020.
- **Other Revenues** decreased $7 million primarily due to a decrease at I&M in barging revenues by River Transportation Division (RTD).This decrease was partially offset in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses decreased $27 million primarily due to the following:
  - A $23 million decrease in distribution expenses primarily related to vegetation management, storms and other distribution expenses.
  - A $13 million decrease in plant outage and maintenance expenses primarily at I&M, SWEPCo, PSO and KPCo.
  - An $8 million decrease due to the modification of the NSR consent decree impacting I&M and AEGCo in 2019.
  - A $4 million decrease in transmission expenses primarily related to RTO fees, NERC activities and station/line inspections.
  - A $4 million decrease in customer-related expenses.

  These decreases were partially offset by:
  - A $30 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $35 million primarily due to a higher depreciable base and increased depreciation rates approved at I&M and SWEPCo. This increase was partially offset in Retail Margins above.
- **Income Tax Expense** increased $6 million primarily due to a decrease in amortization of Excess ADIT, partially offset by a decrease in pretax book income and an increase in favorable flow-through tax benefits. The decrease in amortization of Excess ADIT is partially offset above in Gross Margin and Other Operation and Maintenance expenses.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2019	$	917.7
Changes in Gross Margin:		
Retail Margins		38.5
Margins from Off-system Sales		(14.2)
Transmission Revenues		48.7
Other Revenues		(8.9)
Total Change in Gross Margin		64.1
Changes in Expenses and Other:		
Other Operation and Maintenance		85.3
Depreciation and Amortization		(94.2)
Taxes Other Than Income Taxes		(8.5)
Other Income		(2.1)
Allowance for Equity Funds Used During Construction		(5.8)
Non-Service Cost Components of Net Periodic Pension Cost		0.1
Interest Expense		(3.9)
Total Change in Expenses and Other		(29.1)
Income Tax Expense		(58.9)
Equity Earnings of Unconsolidated Subsidiary		(0.1)
Net Income Attributable to Noncontrolling Interests		1.0
Nine Months Ended September 30, 2020	$	894.7

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

- **Retail Margins** increased $39 million primarily due to the following:
  - A $35 million increase in deferred fuel at APCo and WPCo primarily due to the timing of recoverable PJM expenses.
  - A $16 million increase due to a decrease in customer refunds related to Tax Reform. This increase was partially offset in Income Tax Expense below.
  - A $15 million increase at APCo and WPCo due to the WVPSC approval of the Mitchell Plant surcharge effective January 1, 2020. Pursuant to the WVPSC approval of the surcharge, this increase was partially offset by the amortization of Excess ADIT not subject to normalization requirements in Income Tax Expense below.
  - A $14 million increase due to the impact of the 2019 WVPSC order which required APCo and WPCo to offset Excess ADIT not subject to normalization requirements against the deferred fuel under-recovery balance in 2019.
  - The effect of rate proceedings in AEP's service territories which included:
    - A $72 million increase at I&M primarily due to the Indiana and Michigan base rate cases and an overall increase in revenue from rate riders. This increase was partially offset in other expense items below.
    - A $35 million increase at SWEPCo primarily due to rider increases in all jurisdictions and a base rate revenue increase in Arkansas. This increase was partially offset in other expense items below.
    - A $10 million increase at PSO due to new base rates implemented in April 2019.
    - A $10 million increase at APCo and WPCo due to a base rate increase in West Virginia. This increase was partially offset in Depreciation and Amortization expenses below.
  - A $6 million increase in municipal and cooperative revenues at SWEPCo primarily due to formula rate true-ups.

These increases were partially offset by:
  - A $95 million decrease in weather-related usage primarily in the residential class.
  - A $47 million decrease in weather-normalized margins for wholesale contracts, including the loss of a significant wholesale contract at I&M.
  - A $12 million decrease in weather-normalized retail margins driven by a $93 million decrease in the commercial and industrial classes partially offset by an $85 million increase in the residential customer class.
  - A $10 million decrease in revenue from rate riders at PSO. This decrease was partially offset in other expense items below.
- **Margins from Off-system Sales** decreased $14 million due to weaker market prices for energy in the RTOs which caused a decrease in sales volume and margins and the historical merchant portion of WPCo's Mitchell Plant moving to retail rates beginning in January 2020.
- **Transmission Revenues** increased $49 million primarily due to the following:
  - A $26 million increase due to continued investment in transmission projects primarily at SWEPCo.
  - A $23 million increase as a result of the annual transmission formula rate true-up primarily at SWEPCo.This increase was partially offset by an increase in transmission expenses in SPP.
- **Other Revenues** decreased $9 million primarily due to the following:
  - A decrease of $14 million at I&M primarily due to a decrease in barging revenues by RTD.This decrease was partially offset in Other Operation and Maintenance expenses below.

  This decrease was partially offset by:
  - A $3 million increase at PSO primarily due to business development revenue.This increase was partially offset in other expense items below.

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

- **Other Operation and Maintenance** expenses decreased $85 million primarily due to the following:
  - A $53 million decrease in plant outage and maintenance expenses primarily at APCo, I&M, WPCo, KPCo and PSO.
  - A $22 million decrease in distribution expenses primarily vegetation management and other distribution expenses.
  - A $12 million decrease due to the capitalization of previously expensed North Central Wind Energy Facilities costs at SWEPCo and PSO.
  - A $10 million decrease in transmission expenses primarily related to RTO fees, NERC activities and station/line inspections.
  - An $8 million decrease due to the modification of the NSR consent decree impacting I&M and AEGCo in 2019.
  - A $7 million decrease in PJM transmission services including the annual formula rate true-up.
  - A $7 million decrease at I&M due to an increased Nuclear Electric Insurance Limited distribution in 2020.

  These decreases were partially offset by:
  - A $39 million increase due to SPP transmission services including the annual formula rate true-up.
  - A $10 million increase due to storms primarily at KPCo and PSO.
  - A $3 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $94 million primarily due to a higher depreciable base and increased depreciation rates approved at I&M, APCo and SWEPCo. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $9 million primarily due to the following:
  - A $6 million increase in property taxes due to additional investments in utility plant.
  - A $3 million increase in state business and occupation taxes at APCo due to the reduction of the revitalization tax credit.
- **Allowance for Equity Funds Used During Construction**decreased $6 million primarily due to a decrease in the AFUDC base at I&M and the favorable impact of a FERC settlement agreement recorded in 2019.
- **Interest Expense** increased $4 million primarily due to higher long-term debt balances at APCo.
- **Income Tax Expense** increased $59 million primarily due to a decrease in amortization of Excess ADIT and an increase in pretax book income. The decrease in amortization of Excess ADIT is partially offset above in Gross Margin and Other Operation and Maintenance expenses.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
	(in millions)			
Revenues	$ 1,165.3	$ 1,186.6	$ 3,306.7	$ 3,454.3
Purchased Electricity	183.8	210.1	522.7	603.5
Amortization of Generation Deferrals	—	8.8	—	65.3
Gross Margin	981.5	967.7	2,784.0	2,785.5
Other Operation and Maintenance	439.1	405.8	1,158.2	1,222.1
Depreciation and Amortization	163.5	209.3	585.0	586.4
Taxes Other Than Income Taxes	156.4	151.8	444.4	437.2
Operating Income	222.5	200.8	596.4	539.8
Interest and Investment Income	0.9	1.1	2.0	4.2
Carrying Costs Income	0.3	0.3	1.3	0.7
Allowance for Equity Funds Used During Construction	9.0	9.8	23.7	22.3
Non-Service Cost Components of Net Periodic Benefit Cost	7.4	7.7	22.1	22.8
Interest Expense	(74.0)	(63.6)	(217.6)	(170.8)
Income Before Income Tax Expense (Benefit)	166.1	156.1	427.9	419.0
Income Tax Expense (Benefit)	18.7	22.4	24.8	(2.6)
Net Income	147.4	133.7	403.1	421.6
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 147.4	$ 133.7	$ 403.1	$ 421.6

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
	(in millions of KWhs)			
Retail:				
Residential	8,277	8,268	20,876	20,614
Commercial	6,722	7,219	18,154	19,069
Industrial	5,417	5,857	16,473	17,492
Miscellaneous	206	223	568	595
Total Retail (a)	20,622	21,567	56,071	57,770
Wholesale (b)	502	453	1,347	1,531
Total KWhs	21,124	22,020	57,418	59,301

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in degree days)			
Eastern Region				
Actual – Heating (a)	2	—	1,767	2,006
Normal – Heating (b)	6	6	2,086	2,072
Actual – Cooling (c)	809	872	1,126	1,176
Normal – Cooling (b)	682	672	986	973
Western Region				
Actual – Heating (a)	1	—	98	180
Normal – Heating (b)	—	—	188	190
Actual – Cooling (d)	1,357	1,587	2,524	2,679
Normal – Cooling (b)	1,378	1,368	2,436	2,425

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

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Third Quarter of 2019	$	133.7
Changes in Gross Margin:		
Retail Margins		54.8
Margins from Off-system Sales		(1.4)
Transmission Revenues		15.8
Other Revenues		(55.4)
Total Change in Gross Margin		13.8
Changes in Expenses and Other:		
Other Operation and Maintenance		(33.3)
Depreciation and Amortization		45.8
Taxes Other Than Income Taxes		(4.6)
Interest and Investment Income		(0.2)
Allowance for Equity Funds Used During Construction		(0.8)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(10.4)
Total Change in Expenses and Other		(3.8)
Income Tax Expense		3.7
Third Quarter of 2020	$	147.4

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

- **Retail Margins** increased $55 million primarily due to the following:
  - A $52 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - An $18 million increase in rider revenues in Ohio associated with the DIR. This increase was partially offset in other expense items below.
  - A $9 million increase in weather-normalized margins primarily in the residential class and partially offset in the commercial and industrial classes.
  - A $6 million increase from interim rate increases driven by increased distribution investment in Texas.
  - A $5 million increase in revenues in Ohio associated with the Universal Service Fund (USF).This increase was offset in Other Operation and Maintenance expenses below.
  - A $5 million increase due to new base rates implemented in June 2020 in Texas.
  - A $3 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.

  These increases were partially offset by:
  - A $19 million decrease due to refunds in Texas of Excess ADIT and excess federal income taxes collected as a result of Tax Reform. This decrease was offset in Income Tax Expense below.
  - An $11 million decrease in weather-related usage in Texas primarily due to a 14% decrease in cooling degree days.
  - A $6 million decrease due to the OVEC PPA Rider which was replaced by the Legacy Generation Resource Rider (LGRR).This decrease was offset in Margins from Off-system Sales and Other Revenues below.
  - A $3 million decrease in revenues associated with a vegetation management rider in Ohio. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $3 million decrease due to refunds to customers associated with the most recent base rate case in Texas. This decrease was offset in Other Revenues below.

- **Transmission Revenues** increased $16 million primarily due to the following:
  - An $11 million increase from interim rate increases driven by increased transmission investment in Texas.
  - A $7 million increase in Ohio due to the annual transmission formula rate true-up.
  - A $4 million increase primarily due to recovery of increased transmission investment in PJM.

  These increases were partially offset by:
  - A $7 million decrease due to refunds to customers associated with the most recent base rate case in Texas. This decrease was offset in Other Revenues below.
- **Other Revenues** decreased $55 million primarily due to the following:
  - A $68 million decrease in securitization revenues due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This increase was offset in Depreciation and Amortization expenses and Interest Expense below.

  This decrease was partially offset by:
  - An $8 million increase in revenues due to the amortization of a provision for refund recorded in December 2019 as part of the most recent base rate case in Texas. This increase was partially offset in Retail Margins and Transmission Revenues above.

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

- **Other Operation and Maintenance** expenses increased $33 million primarily due to the following:
  - A $50 million increase in transmission expenses primarily due to an increase in PJM and ERCOT expenses.This increase was offset in Gross Margin above.
  - A $5 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.

  These decreases were partially offset by:
  - A $16 million decrease in distribution expenses. This decrease was partially offset in Gross Margins above.
- **Depreciation and Amortization** expenses decreased $46 million primarily due to the following:
  - A $63 million decrease in securitization amortizations in Texas due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This increase was offset in Other Revenues above and Interest Expense below.

  This decrease was partially offset by:
  - A $9 million increase in Ohio recoverable DIR depreciation expense. This increase was partially offset in Retail Margins above.
  - A $5 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- **Taxes Other Than Income Taxes** increased $5 million primarily due to property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Interest Expense** increased $10 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $4 million primarily due to an increase in amortization of Excess ADIT, partially offset by an increase in pretax book income. This decrease was partially offset in Gross Margins and Other Operation and Maintenance Expenses above.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2019	$	421.6
Changes in Gross Margin:		
Retail Margins		8.7
Margins from Off-system Sales		(17.3)
Transmission Revenues		31.7
Other Revenues		(24.6)
Total Change in Gross Margin		(1.5)
Changes in Expenses and Other:		
Other Operation and Maintenance		63.9
Depreciation and Amortization		1.4
Taxes Other Than Income Taxes		(7.2)
Interest and Investment Income		(2.2)
Carrying Costs Income		0.6
Allowance for Equity Funds Used During Construction		1.4
Non-Service Cost Components of Net Periodic Benefit Cost		(0.7)
Interest Expense		(46.8)
Total Change in Expenses and Other		10.4
Income Tax Expense		(27.4)
Nine Months Ended September 30, 2020	$	403.1

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** increased $9 million primarily due to the following:
  - A $74 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $48 million increase in rider revenues in Ohio associated with the DIR. This increase was partially offset in other expense items below.
  - A $15 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.
  - A $15 million increase in revenues in Ohio associated with the USF. This increase was offset in Other Operation and Maintenance expenses below.
  - An $8 million increase in weather-normalized margins primarily in the residential class and partially offset in the industrial and commercial classes.
  - A $7 million increase from interim rate increases driven by increased transmission investment in Texas.
  - A $7 million increase from interim rate increases driven by increased distribution investment in Texas.
  - A $7 million increase due to new base rates implemented in June 2020 in Texas.
  - A $5 million increase due to the change in the recording of merger savings as authorized by the PUCT in the most recent base rate case.

  These increases were partially offset by:
  - A $58 million decrease due to a reversal of a regulatory provision in Ohio in the first quarter of 2019.
  - A $25 million decrease due to refunds in Texas of Excess ADIT and excess federal income taxes collected as a result of Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $23 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 $21 million decrease due to the OVEC PPA Rider which was replaced by the LGRRThis decrease was offset in Margins from Off-system Sales and Other Revenues below.
- A $17 million net decrease in margin in Ohio for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
- A $15 million decrease in weather-related usage in Texas primarily due to a 6% decrease in cooling degree days and a 46% decrease in heating degree days.
- A $9 million decrease in revenues associated with a vegetation management rider in Ohio. This decrease was offset in Other Operation and Maintenance expenses below.
- A $5 million decrease due to a PUCO order to refund unused 2018 major storm reserve collections to customers.This decrease was offset in Other Operation and Maintenance expenses below.
- A $4 million decrease due to refunds to customers associated with the most recent base rate case in Texas. This decrease was offset in Other Revenues below.

- **Margins from Off-system Sales** decreased $17 million primarily due to the following:
  - A $20 million decrease in Texas primarily due to lower Oklaunion Power Station PPA revenues. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $12 million decrease in sales in Ohio due to lower market prices and decreased sales volumes in 2020. This decrease was offset in Retail Margins above.

  These decreases were partially offset by:
  - An $18 million increase in Ohio due to higher OVEC PPA deferrals. This increase was offset in Retail Margins above.
- **Transmission Revenues** increased $32 million primarily due to the following:
  - A $30 million increase from interim rate increases driven by increased transmission investment in Texas.
  - A $16 million increase in Ohio due to the annual transmission formula rate true-up.
  - A $6 million increase due to additional investment in transmission assets in Ohio.

  These increases were partially offset by:
  - A $14 million decrease in Texas due to a one-time credit to transmission customers as a result of Tax Reform and the most recent base rate case. This decrease was offset in Income Tax Expense below.
  - A $7 million decrease due to refunds to customers associated with the most recent base rate case in Texas. This decrease is offset in Other Revenues below.
- **Other Revenues** decreased $25 million primarily due to the following:
  - A $49 million decrease in securitization revenue due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset in Depreciation and Amortization expenses and Interest Expense below.

  This decrease was partially offset by:
  - A $12 million increase in Ohio primarily due to third-party LGRR revenue related to the recovery of OVEC costsThis increase was offset in Retail Margins above.
  - An $11 million increase in revenues due to the amortization of a provision for refund recorded in December 2019 as part of the most recent base rate case in Texas. This increase was offset in Retail Margins and Transmission Revenues above.

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

- **Other Operation and Maintenance** expenses decreased $64 million primarily due to the following:
  - A $67 million decrease due to prior year partial amortization of the AEP Texas Storm Restoration Securitization regulatory asset as a result of the AEP Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.This decrease was offset in Income Tax Expense below.
  - A $17 million decrease due to the revision of the Oklaunion Power Station ARO.This decrease was offset in Margins for Off-System Sales above.
  - A $15 million decrease in distribution expenses primarily due to vegetation management. This decrease was partially offset in Retail Margins above.
  - A $5 million decrease due to a PUCO order to refund unused 2018 major storm reserve collections to customers.This decrease was offset in Retail Margins above.

These decreases were partially offset by:

- A $41 million increase in transmission expenses primarily due to a $68 million increase in recoverable PJM and ERCOT expenses partially offset by a $28 million decrease related to the annual PJM transmission formula rate true-up. This increase was offset in Gross Margin above.
- A $15 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.

- **Depreciation and Amortization** expenses decreased $1 million primarily due to the following:
  - A $43 million decrease in securitization amortizations due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset in Other Revenues above and Interest Expense below.
  - A $24 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.

  These decreases were partially offset by:
  - A $27 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $16 million increase in Ohio recoverable DIR depreciation expense. This increase was partially offset in Retail Margins above.
  - 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 $7 million increase in amortizations primarily due to capitalized software.
  - A $6 million increase in recoverable smart grid expense in Ohio. This increase was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to the following:
  - A $13 million increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.

  This increase was partially offset by:
  - A $4 million decrease in excise taxes due to lower demand in 2020 in Ohio. This decrease was offset in Retail Margins above.
- **Interest Expense** increased $47 million primarily due to the following:
  - A $24 million increase 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 $21 million increase due to higher long-term debt balances.
  - A $7 million increase due to due to a decrease in the debt component of AFUDC.

  These increases were partially offset by:
  - A $5 million decrease due to lower short-term debt balances.
- **Income Tax Expense** increased $27 million primarily due to the prior year amortization of Excess ADIT not subject to normalization requirements as approved in the Texas Storm Cost Securitization financing order issued by the PUCT in 2019 partially offset by current year amortization of Excess ADIT and an increase in favorable AFUDC Equity tax benefit.This increase was partially offset in Gross Margins and Other Operation and Maintenance Expenses above.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
	(in millions)			
Transmission Revenues	$ 317.9	$ 273.0	$ 877.8	$ 808.3
Other Operation and Maintenance	30.1	31.8	85.9	77.0
Depreciation and Amortization	63.6	47.3	182.8	133.7
Taxes Other Than Income Taxes	53.8	44.3	157.5	130.4
Operating Income	170.4	149.6	451.6	467.2
Interest and Investment Income	0.2	0.8	2.6	2.3
Allowance for Equity Funds Used During Construction	20.3	21.0	54.9	61.1
Non-Service Cost Components of Net Periodic Benefit Cost	0.5	0.7	1.5	2.0
Interest Expense	(34.0)	(27.8)	(99.0)	(73.8)
Income Before Income Tax Expense and Equity Earnings	157.4	144.3	411.6	458.8
Income Tax Expense	38.2	35.4	101.3	105.7
Equity Earnings of Unconsolidated Subsidiary	20.1	18.1	62.8	54.5
Net Income	139.3	127.0	373.1	407.6
Net Income Attributable to Noncontrolling Interests	1.0	0.9	2.7	2.8
Earnings Attributable to AEP Common Shareholders	$ 138.3	$ 126.1	$ 370.4	$ 404.8

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	September 30, 2020	September 30, 2019
	(in millions)	
Plant in Service	$ 9,644.6	$ 7,796.9
Construction Work in Progress	1,732.5	1,903.4
Accumulated Depreciation and Amortization	553.1	383.7
Total Transmission Property, Net	$ 10,824.0	$ 9,316.6

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2019	$	126.1
Changes in Transmission Revenues:		
Transmission Revenues		44.9
Total Change in Transmission Revenues		44.9
Changes in Expenses and Other:		
Other Operation and Maintenance		1.7
Depreciation and Amortization		(16.3)
Taxes Other Than Income Taxes		(9.5)
Interest and Investment Income		(0.6)
Allowance for Equity Funds Used During Construction		(0.7)
Non-Service Cost Components of Net Periodic Pension Cost		(0.2)
Interest Expense		(6.2)
Total Change in Expenses and Other		(31.8)
Income Tax Expense		(2.8)
Equity Earnings of Unconsolidated Subsidiary		2.0
Net Income Attributable to Noncontrolling Interests		(0.1)
Third Quarter of 2020	$	138.3

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

- **Transmission Revenues** increased $45 million primarily due to continued investment in transmission assets.

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

- **Depreciation and Amortization** expenses increased $16 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $10 million primarily due to higher property taxes as a result of increased transmission investment.
- **Interest Expense** increased $6 million primarily due to higher long-term debt balances.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2019	$	404.8
Changes in Transmission Revenues:		
Transmission Revenues		69.5
Total Change in Transmission Revenues		69.5
Changes in Expenses and Other:		
Other Operation and Maintenance		(8.9)
Depreciation and Amortization		(49.1)
Taxes Other Than Income Taxes		(27.1)
Interest and Investment Income		0.3
Allowance for Equity Funds Used During Construction		(6.2)
Non-Service Cost Components of Net Periodic Pension Cost		(0.5)
Interest Expense		(25.2)
Total Change in Expenses and Other		(116.7)
Income Tax Expense		4.4
Equity Earnings of Unconsolidated Subsidiary		8.3
Net Income Attributable to Noncontrolling Interests		0.1
Nine Months Ended September 30, 2020	$	370.4

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

- **Transmission Revenues** increased $70 million primarily due to the following:
  - A $149 million increase due to continued investment in transmission assets.

  This increase was partially offset by the following:
  - A $62 million decrease as a result of the affiliated annual transmission formula rate true-up which is offset in Other Operation and Maintenance expense across the other Registrant subsidiaries.
  - A $17 million decrease as a result of the non-affiliated annual transmission formula rate true-up.

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

- **Other Operation and Maintenance** expenses increased $9 million primarily due to the following:
  - A $5 million increase in rent expense.
  - A $3 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $49 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $27 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** decreased $6 million primarily due to the following:
  - A $12 million decrease driven by the favorable impact of a FERC settlement agreement recorded in 2019.
  - An $8 million decrease due to lower CWIP.

  These decreases were partially offset by:
  - A $13 million increase driven by FERC audit findings recorded in 2019.
- **Interest Expense** increased $25 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $4 million primarily due to lower pretax book income, partially offset by the recognition of a discrete tax adjustment in 2019.
- **Equity Earnings of Unconsolidated Subsidiary** increased $8 million primarily due to higher pretax equity earnings at PATH-WV and ETT.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
	(in millions)			
Revenues	$ 490.0	$ 533.7	$ 1,305.5	$ 1,428.2
Fuel, Purchased Electricity and Other	391.6	403.8	1,050.4	1,117.8
Gross Margin	98.4	129.9	255.1	310.4
Other Operation and Maintenance	27.2	44.0	85.1	158.0
Depreciation and Amortization	18.5	20.6	54.1	49.1
Taxes Other Than Income Taxes	3.3	4.4	10.4	11.8
Operating Income	49.4	60.9	105.5	91.5
Interest and Investment Income	0.4	1.9	2.6	6.0
Non-Service Cost Components of Net Periodic Benefit Cost	3.9	3.8	11.6	11.2
Interest Expense	(3.8)	(10.5)	(20.5)	(21.5)
Income Before Income Tax Benefit and Equity Earnings (Loss)	49.9	56.1	99.2	87.2
Income Tax Benefit	(70.9)	(36.4)	(104.3)	(51.8)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(6.2)	(3.8)	0.1	(5.9)
Net Income	114.6	88.7	203.6	133.1
Net Loss Attributable to Noncontrolling Interests	(2.1)	(1.3)	(7.4)	(6.4)
Earnings Attributable to AEP Common Shareholders	$ 116.7	$ 90.0	$ 211.0	$ 139.5

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
	(in millions of MWhs)			
Fuel Type:				
Coal	1	2	3	4
Renewables	—	1	2	2
Total MWhs	1	3	5	6

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2019	$	90.0
Changes in Gross Margin:		
Merchant Generation		(24.3)
Renewable Generation		(4.1)
Retail, Trading and Marketing		(3.1)
Total Change in Gross Margin		(31.5)
Changes in Expenses and Other:		
Other Operation and Maintenance		16.8
Depreciation and Amortization		2.1
Taxes Other Than Income Taxes		1.1
Interest and Investment Income		(1.5)
Non-Service Cost Components of Net Periodic Benefit Cost		0.1
Interest Expense		6.7
Total Change in Expenses and Other		25.3
Income Tax Benefit		34.5
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(2.4)
Net Loss Attributable to Noncontrolling Interests		0.8
Third Quarter of 2020	$	116.7

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

- **Merchant Generation** decreased $24 million primarily due to lower capacity revenues and energy margins in 2020 and the retirement of the Conesville Plant Units 5 and 6 in 2019 and Unit 4 in 2020.
- **Renewable Generation** decreased $4 million primarily due to lower wind production.
- **Retail, Trading and Marketing** decreased $3 million due to lower trading and marketing activity, partially offset by higher retail margins.

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

- **Other Operation and Maintenance** expenses decreased $17 million primarily due to the following:
  - An $11 million decrease due to a gain recorded on the sale of land.
  - An $8 million decrease due to the retirement of Conesville Plant Units 5 and 6 in 2019 and Unit 4 in 2020.
- **Interest Expense** decreased $7 million due to lower borrowing costs in 2020.
- **Income Tax Benefit** increased $35 million primarily due to the recognition of a discrete tax adjustment in 2020, which was attributable to the CARES Act offset by a decrease in PTC.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Nine Months Ended September 30, 2019	$	139.5
Changes in Gross Margin:		
Merchant Generation		(78.3)
Renewable Generation		17.4
Retail, Trading and Marketing		5.6
Total Change in Gross Margin		(55.3)
Changes in Expenses and Other:		
Other Operation and Maintenance		72.9
Depreciation and Amortization		(5.0)
Taxes Other Than Income Taxes		1.4
Interest and Investment Income		(3.4)
Non-Service Cost Components of Net Periodic Benefit Cost		0.4
Interest Expense		1.0
Total Change in Expenses and Other		67.3
Income Tax Benefit		52.5
Equity Earnings (Loss) of Unconsolidated Subsidiaries		6.0
Net Loss Attributable to Noncontrolling Interests		1.0
Nine Months Ended September 30, 2020	$	211.0

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

- **Merchant Generation** decreased $78 million primarily due to the reduction of capacity revenues and energy margins in 2020 and the retirement of the Conesville Plant Units 5 and 6 in 2019 and Unit 4 in 2020.
- **Renewable Generation** increased $17 million primarily due to the Sempra Renewables LLC acquisition and other renewable projects placed in-service.
- **Retail, Trading and Marketing** increased $6 million due to higher trading and marketing activity, partially offset by lower retail margins.

Expenses and Other, Income Tax Benefit and Equity Earnings (Loss) of Unconsolidated Subsidiaries changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $73 million due to the following:
  - A $34 million decrease due to the retirement of Conesville Plant Units 5 and 6 in 2019 and Unit 4 in 2020.
  - A $26 million decrease due to a gain recorded on the sale of land.
  - A $16 million decrease related to the Oklaunion PPA with AEP Texas primarily due to an ARO revision.
- **Depreciation and Amortization** expenses increased $5 million due to a higher depreciable base from increased investments in renewable energy sources.
- **Interest and Investment Income** decreased $3 million due to lower returns on investments.
- **Income Tax Benefit** increased $53 million primarily due the recognition of a discrete tax adjustment in 2020, which was attributable to the CARES Act and an increase in PTC.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** increased $6 million primarily due to the Sempra Renewables LLC acquisition.

CORPORATE AND OTHER

Third Quarter of 2020 Compared to Third Quarter of 2019

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $54 million in 2019 to a loss of $47 million in 2020 primarily due to:

- A $12 million decrease in income tax expense due to a decrease in consolidating tax adjustments.
- A $6 million decrease in interest expense as a result of a decrease in debt outstanding.

These items were partially offset by:

- A $5 million increase in general corporate expenses.
- A $6 million decrease in interest income.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $116 million in 2019 to a loss of $115 million in 2020 primarily due to:

- An $11 million decrease in general corporate expenses.
- A $5 million write-off of an equity investment and related assets in 2019.
- A $2 million decrease in income tax expense due to discrete items recorded in 2020, partially offset by an increase in consolidating tax adjustments.

These items were partially offset by:

- An $8 million decrease in interest income.
- An $8 million increase in interest expense as a result of an increase in debt outstanding.

AEP SYSTEM INCOME TAXES

Third Quarter of 2020 Compared to Third Quarter of 2019

Income Tax Expense decreased $42 million primarily due to the recognition of a $52 million discrete tax adjustment in 2020, which was attributable to the 5-year net operating loss carryback provision of the CARES Act.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Income Tax Expense increased $27 million primarily due to a decrease in amortization of Excess ADIT, partially offset by the recognition of the discrete tax adjustment in 2020, which was attributable to the 5-year net operating loss carryback provision of the CARES Act.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2020		December 31, 2019	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 30,067.1	56.6 %	$ 26,725.5	54.1 %
Short-term Debt	2,397.0	4.5	2,838.3	5.7
Total Debt	32,464.1	61.1	29,563.8	59.8
AEP Common Equity	20,365.9	38.4	19,632.2	39.6
Noncontrolling Interests	268.7	0.5	281.0	0.6
Total Debt and Equity Capitalization	$ 53,098.7	100.0 %	$ 49,477.0	100.0 %

AEP's ratio of debt-to-total capital increased from 59.8% as of December 31, 2019 to 61.1% as of September 30, 2020 primarily due to an increase in debt to support distribution, transmission and renewable investment growth.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of September 30, 2020, 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. There was increased volatility in the capital markets during the first quarter of 2020 resulting in higher commercial paper cost and limited access. To address these issues and the uncertainty around COVID-19, in March 2020, AEP entered into a $1 billion 364-day Term Loan and borrowed the full amount.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of September 30, 2020, available liquidity was approximately $3.8 billion as illustrated in the table below:

		Amount	Maturity
Commercial Paper Backup:		(in millions)	
	Revolving Credit Facility	$ 4,000.0	June 2022
	364-Day Term Loan	1,000.0	March 2021
Cash and Cash Equivalents		409.7	
Total Liquidity Sources		5,409.7	
Less:	AEP Commercial Paper Outstanding	650.0	
	364-Day Term Loan	1,000.0	
Net Available Liquidity		$ 3,759.7	

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. The maximum amount of commercial paper outstanding during the first nine months of 2020 was $3 billion. The weighted-average interest rate for AEP's commercial paper during 2020 was 1.56%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $405 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2020 was $197 million with maturities ranging from October 2020 to August 2021.

Securitized Accounts Receivables

AEP's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in September 2022.

In May 2020, AEP Credit amended its receivables securitization agreement to increase the eligibility criteria related to aged receivable requirements for the participating affiliated utility subsidiaries in response to the COVID-19 pandemic.As of September 30, 2020, the affiliated utility subsidiaries are in compliance with all requirements under the agreement. To the extent that an affiliated utility subsidiary is deemed ineligible under the agreement, receivables would no longer be purchased by the bank conduits and the Registrants would need to rely on additional sources of funding for operation and working capital, which may adversely impact liquidity.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreement excludes securitization bonds and debt of AEP Credit. As of September 30, 2020, this contractually-defined percentage was 57.7%. 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 August 2020, AEP issued 17 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $850 million. Net proceeds from the issuance were approximately $833 million. Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 1.30% Junior Subordinated Notes due in 2025 and a forward equity purchase contract which settles after three years in 2023. The proceeds were used to support AEP's overall capital expenditure plans.

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 acquisition of Sempra Renewables LLC.

See Note 12 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.74 per share in October 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 12 for additional information.

Credit Ratings

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

CASH FLOW

AEP relies primarily on cash flows from operations, debt issuances and its existing cash and cash equivalents to fund its liquidity and investing activities. AEP's investing and capital requirements are primarily capital expenditures, repaying of long-term debt and paying dividends to shareholders. AEP uses short-term debt, including commercial paper, as a bridge to long-term debt financing. The levels of borrowing may vary significantly due to the timing of long-term debt financings and the impact of fluctuations in cash flows.

	Nine Months Ended September 30,	
	2020	**2019**
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 432.6	$ 444.1
Net Cash Flows from Operating Activities	2,922.2	3,349.9
Net Cash Flows Used for Investing Activities	(4,707.3)	(5,357.6)
Net Cash Flows from Financing Activities	1,816.3	2,053.4
Net Increase in Cash, Cash Equivalents and Restricted Cash	31.2	45.7
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 463.8	$ 489.8

Operating Activities

	Nine Months Ended September 30,	
	2020	2019
	(in millions)	
Net Income	$ 1,762.0	$ 1,767.1
Non-Cash Adjustments to Net Income (a)	2,094.3	1,838.8
Mark-to-Market of Risk Management Contracts	46.4	(41.6)
Pension Contributions to Qualified Plan Trust	(110.3)	—
Property Taxes	396.9	341.7
Deferred Fuel Over/Under-Recovery, Net	27.4	93.7
Recovery of Ohio Capacity Costs	—	34.1
Refund of Global Settlement	—	(12.4)
Change in Other Noncurrent Assets	(219.6)	(9.6)
Change in Other Noncurrent Liabilities	(25.1)	(16.3)
Change in Certain Components of Working Capital	(1,049.8)	(645.6)
Net Cash Flows from Operating Activities	$ 2,922.2	$ 3,349.9

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

Net Cash Flows from Operating Activities decreased by $428 million primarily due to the following:

- A $404 million decrease in cash from the Change in Certain Components of Working Capital. The decrease is primarily due to timing of accounts receivable, an increase in employee-related payments and a decrease in accrued taxes primarily due to increased property tax payments.
- A $210 million decrease in Changes in Other Noncurrent Assets primarily due to a change in regulatory assets as a result of deferred storm costs related to Hurricane Laura in 2020 and the settlement of deferred restoration costs from the Texas Storm Cost Securitization financing order received in 2019. See Note 4 - Rate Matters for additional information.
- A $110 million decrease in cash due to a discretionary contribution to the qualified pension plan. See Note 7 - Benefit Plans for additional information.

These decreases in cash were partially offset by:

- A $250 million increase in cash from Income from Continuing Operations, after non-cash adjustments. See Results of Operations for further detail.
- An $88 million increase in fair value of risk management contracts due to pricing movement in the commodities markets.

Investing Activities

	Nine Months Ended September 30,	
	2020	2019
	(in millions)	
Construction Expenditures	$ (4,690.4)	$ (4,336.0)
Acquisitions of Nuclear Fuel	(68.4)	(91.9)
Acquisition of Sempra Renewables LLC and Santa Rita East, Net of Cash and Restricted Cash Acquired	—	(921.3)
Other	51.5	(8.4)
Net Cash Flows Used for Investing Activities	$ (4,707.3)	$ (5,357.6)

Net Cash Flows Used for Investing Activities decreased by $650 million primarily due to the following:

- A $921 million decrease due to the 2019 acquisition of Sempra Renewables LLC and Santa Rita East.The $921 million represented a cash payment of $939 million, net of cash acquired of $18 million. See Note 6 - Acquisition and Dispositions for additional information.

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

- A $354 million increase in construction expenditures, primarily due to increases at AEP Transmission Holdco of $189 million, Generation & Marketing of $76 million and Transmission and Distribution Utilities of $55 million.

Financing Activities

	Nine Months Ended September 30,	
	2020	2019
	(in millions)	
Issuance of Common Stock	$ 136.5	$ 44.7
Issuance/Retirement of Debt, Net	2,844.0	3,063.9
Dividends Paid on Common Stock	(1,055.7)	(1,002.0)
Other	(108.5)	(53.2)
Net Cash Flows from Financing Activities	$ 1,816.3	$ 2,053.4

Net Cash Flows from Financing Activities decreased by $237 million primarily due to the following:

- A $1 billion decrease in short-term debt primarily due to increased repayments of commercial paper. See Note 12 - Financing Activities for additional information.

This decrease in cash was partially offset by:

- A $493 million increase in issuances of long-term debt. See Note 12 - Financing Activities for additional information.
- A $323 million decrease in the retirement of long-term debt. See Note 12 - Financing Activities for additional information.

See "Long-term Debt Subsequent Events" section of Note 12 for Long-term debt and other securities issued, retired and principal payments made after September 30, 2020 through October 22, 2020, the date that the third quarter 10-Q was issued.

BUDGETED CAPITAL EXPENDITURES

Management currently estimates $5.9 billion of capital expenditures for 2020 and forecasts approximately $34.9 billion of capital expenditures for 2020 to 2024. In the second quarter of 2020, management revised the capital expenditure forecast for 2020 to 2024 to include approximately $2 billion of capital expenditures for North Central Wind Energy Facilities.The expenditures are generally for transmission, generation, distribution, regulated and contracted renewables, and required environmental investment to comply with the Federal EPA rules. Estimated capital expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. Management expects to fund these capital expenditures through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. For complete information of forecasted capital expenditures, see the "Budgeted Capital Expenditures" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2019 Annual Report.

CONTRACTUAL OBLIGATION INFORMATION

A summary of contractual obligations is included in the 2019 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the "Cash Flow" section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the "Critical Accounting Policies and Estimates" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2019 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting standards.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards adopted in 2020 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, Executive Vice President of Utilities, 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 effects of COVID-19 may adversely impact AEP's risk management contracts on a forward basisMarkets could experience reduced market liquidity as they face potential uncertainties. Credit risk may increase as counterparties encounter business and supply chain disruptions and overall solvency challenges. Also, interest rates could continue to see increased volatility as capital markets confront uncertainty.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2019:

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2020

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2019	$ 75.9	$ (103.6)	$ 163.4	$ 135.7
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(43.8)	(5.1)	(16.6)	(65.5)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	12.0	12.0
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	10.7	10.7
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	26.9	(4.9)	—	22.0
Total MTM Risk Management Contract Net Assets (Liabilities) as of September 30, 2020	$ 59.0	$ (113.6)	$ 169.5	114.9
Commodity Cash Flow Hedge Contracts				(55.6)
Interest Rate Cash Flow Hedge Contracts				(4.7)
Collateral Deposits				8.7
Total MTM Derivative Contract Net Assets as of September 30, 2020				$ 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 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

Credit risk is mitigated in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEP has risk management contracts (includes non-derivative contracts) with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of September 30, 2020, credit exposure net of collateral to sub investment grade counterparties was approximately 7.2%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of September 30, 2020, 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	$ 401.8	$ —	$ 401.8	2	$ 194.8
Split Rating	0.8	—	0.8	1	0.8
No External Ratings:					
Internal Investment Grade	128.0	—	128.0	3	87.1
Internal Noninvestment Grade	51.9	10.5	41.4	2	28.0
Total as of September 30, 2020	$ 582.5	$ 10.5	$ 572.0		

All exposure in the table above relates to AEPSC and AEPEP as AEPSC is agent for and transacts on behalf of AEP subsidiaries, including the Registrant Subsidiaries and AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of September 30, 2020, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

VaR Model
Trading Portfolio

Nine Months Ended September 30, 2020				Twelve Months Ended December 31, 2019			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.1	$ 0.3	$ 0.1	$ —	$ 0.1	$ 1.2	$ 0.2	$ 0.1

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2020				Twelve Months Ended December 31, 2019			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 1.0	$ 1.5	$ 0.8	$ 0.1	$ 0.2	$ 8.5	$ 1.1	$ 0.2

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

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

Interest Rate Risk

AEP is exposed to interest rate market fluctuations in the normal course of business operations. AEP has outstanding short and long-term debt which is subject to a variable rate. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the nine months ended September 30, 2020 and 2019, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $18 million and $24 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
REVENUES				
Vertically Integrated Utilities	$ 2,400.1	$ 2,598.9	$ 6,655.4	$ 7,087.6
Transmission and Distribution Utilities	1,124.1	1,147.3	3,208.7	3,328.7
Generation & Marketing	464.8	501.2	1,223.4	1,323.8
Other Revenues	77.4	67.6	220.4	205.3
TOTAL REVENUES	4,066.4	4,315.0	11,307.9	11,945.4
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	459.3	631.2	1,174.9	1,662.5
Purchased Electricity for Resale	741.1	783.9	2,141.4	2,306.4
Other Operation	702.9	708.3	1,871.0	1,981.7
Maintenance	237.6	267.7	730.5	890.9
Depreciation and Amortization	644.6	645.2	1,996.3	1,873.6
Taxes Other Than Income Taxes	337.7	320.5	976.3	932.7
TOTAL EXPENSES	3,123.2	3,356.8	8,890.4	9,647.8
OPERATING INCOME	943.2	958.2	2,417.5	2,297.6
Other Income (Expense):				
Other Income	5.5	3.2	15.4	18.4
Allowance for Equity Funds Used During Construction	45.2	43.0	111.7	122.3
Non-Service Cost Components of Net Periodic Benefit Cost	29.7	30.0	89.2	90.0
Interest Expense	(291.3)	(275.1)	(877.4)	(781.6)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	732.3	759.3	1,756.4	1,746.7
Income Tax Expense (Benefit)	(1.2)	40.6	57.9	30.7
Equity Earnings of Unconsolidated Subsidiaries	14.7	15.2	63.5	51.1
NET INCOME	748.2	733.9	1,762.0	1,767.1
Net Income (Loss) Attributable to Noncontrolling Interests	(0.4)	0.4	(2.6)	(0.5)
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 748.6	$ 733.5	$ 1,764.6	$ 1,767.6
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	496,177,968	493,839,034	495,479,190	493,579,430
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.51	$ 1.49	$ 3.56	$ 3.58
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	497,458,523	495,461,509	496,916,187	495,105,986
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.50	$ 1.48	$ 3.55	$ 3.57

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
Net Income	$ 748.2	$ 733.9	$ 1,762.0	$ 1,767.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $10.5 and $11.8 for the Three Months Ended September 30, 2020 and 2019, Respectively, and $4.7 and $(16.8) for the Nine Months Ended September 30, 2020 and 2019, Respectively	39.3	44.2	17.6	(63.3)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.5) and $(0.4) for the Three Months Ended September 30, 2020 and 2019, Respectively, and $(1.4) and $(1.1) for the Nine Months Ended September 30, 2020 and 2019, Respectively	(1.8)	(1.4)	(5.3)	(4.2)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	37.5	42.8	12.3	(67.5)
TOTAL COMPREHENSIVE INCOME	785.7	776.7	1,774.3	1,699.6
Total Other Comprehensive Income (Loss) Attributable To Noncontrolling Interests	(0.4)	0.4	(2.6)	(0.5)
TOTAL OTHER COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 786.1	$ 776.3	$ 1,776.9	$ 1,700.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2018	513.5	$ 3,337.4	$ 6,486.1	$ 9,325.3	$ (120.4)	$ 31.0	$ 19,059.4
Issuance of Common Stock	0.1	1.2	13.3				14.5
Common Stock Dividends				(332.5) (b)		(1.1)	(333.6)
Other Changes in Equity			(56.6) (a)			1.0	(55.6)
Net Income				572.8		1.3	574.1
Other Comprehensive Loss					(30.3)		(30.3)
TOTAL EQUITY – MARCH 31, 2019	513.6	3,338.6	6,442.8	9,565.6	(150.7)	32.2	19,228.5
Issuance of Common Stock	0.4	2.2	15.6				17.8
Common Stock Dividends				(332.7) (b)		(1.8)	(334.5)
Other Changes in Equity			(3.1)			0.6	(2.5)
Acquisition of Sempra Renewables LLC						134.8	134.8
Net Income (Loss)				461.3		(2.2)	459.1
Other Comprehensive Loss					(80.0)		(80.0)
TOTAL EQUITY – JUNE 30, 2019	514.0	3,340.8	6,455.3	9,694.2	(230.7)	163.6	19,423.2
Issuance of Common Stock	0.1	1.1	11.3				12.4
Common Stock Dividends				(332.4) (b)		(1.5)	(333.9)
Other Changes in Equity			0.5				0.5
Acquisition of Santa Rita East						118.8	118.8
Net Income				733.5		0.4	733.9
Other Comprehensive Income					42.8		42.8
TOTAL EQUITY – SEPTEMBER 30, 2019	514.1	$ 3,341.9	$ 6,467.1	$ 10,095.3	$ (187.9)	$ 281.3	$ 19,997.7
TOTAL EQUITY – DECEMBER 31, 2019	514.4	$ 3,343.4	$ 6,535.6	$ 9,900.9	$ (147.7)	$ 281.0	$ 19,913.2
Issuance of Common Stock	1.0	6.8	49.3				56.1
Common Stock Dividends				(359.1) (c)		(4.6)	(363.7)
Other Changes in Equity			(29.0)			(1.2)	(30.2)
ASU 2016-13 Adoption				1.8			1.8
Net Income				495.2		4.1	499.3
Other Comprehensive Loss					(68.8)		(68.8)
TOTAL EQUITY – MARCH 31, 2020	515.4	3,350.2	6,555.9	10,038.8	(216.5)	279.3	20,007.7
Issuance of Common Stock	0.8	5.2	49.7				54.9
Common Stock Dividends				(337.7) (c)		(3.2)	(340.9)
Other Changes in Equity			(2.6)			1.0	(1.6)
Net Income (Loss)				520.8		(6.3)	514.5
Other Comprehensive Income					43.6		43.6
TOTAL EQUITY – JUNE 30, 2020	516.2	3,355.4	6,603.0	10,221.9	(172.9)	270.8	20,278.2
Issuance of Common Stock	0.4	2.2	23.3				25.5
Common Stock Dividends				(349.1) (c)		(2.0)	(351.1)
Other Changes in Equity			(104.0) (d)			0.3	(103.7)
Net Income (Loss)				748.6		(0.4)	748.2
Other Comprehensive Income					37.5		37.5
TOTAL EQUITY – SEPTEMBER 30, 2020	516.6	$ 3,357.6	$ 6,522.3	$ 10,621.4	$ (135.4)	$ 268.7	$ 20,634.6

(a) Includes $(62) million related to a forward equity purchase contract associated with the issuance of Equity Units.
(b) Cash dividends declared per AEP common share were $0.67.
(c) Cash dividends declared per AEP common share were $0.70.
(d) Includes $(121) million related to a forward equity purchase contract associated with the issuance of Equity Units.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 409.7	$ 246.8
Restricted Cash (September 30, 2020 and December 31, 2019 Amounts Include $54.1 and $185.8, Respectively, Related to Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Santa Rita East)	54.1	185.8
Other Temporary Investments (September 30, 2020 and December 31, 2019 Amounts Include $198 and $187.8, Respectively, Related to EIS and Transource Energy)	209.0	202.7
Accounts Receivable:		
Customers	600.5	625.3
Accrued Unbilled Revenues	212.4	222.4
Pledged Accounts Receivable – AEP Credit	1,055.1	873.9
Miscellaneous	46.1	27.2
Allowance for Uncollectible Accounts	(63.4)	(43.7)
Total Accounts Receivable	1,850.7	1,705.1
Fuel	586.1	528.5
Materials and Supplies	681.2	640.7
Risk Management Assets	115.2	172.8
Regulatory Asset for Under-Recovered Fuel Costs	61.4	92.9
Margin Deposits	54.1	60.4
Prepayments and Other Current Assets	316.7	242.1
TOTAL CURRENT ASSETS	4,338.2	4,077.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	23,036.9	22,762.4
Transmission	26,539.1	24,808.6
Distribution	23,459.8	22,443.4
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	5,204.7	4,811.5
Construction Work in Progress	4,662.5	4,319.8
Total Property, Plant and Equipment	82,903.0	79,145.7
Accumulated Depreciation and Amortization	20,116.6	19,007.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	62,786.4	60,138.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,518.8	3,158.8
Securitized Assets	684.0	858.1
Spent Nuclear Fuel and Decommissioning Trusts	3,075.9	2,975.7
Goodwill	52.5	52.5
Long-term Risk Management Assets	242.9	266.6
Operating Lease Assets	881.0	957.4
Deferred Charges and Other Noncurrent Assets	3,109.6	3,407.3
TOTAL OTHER NONCURRENT ASSETS	11,564.7	11,676.4
TOTAL ASSETS	$ 78,689.3	$ 75,892.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2020 and December 31, 2019
(in millions, except per-share and share amounts)
(Unaudited)

		September 30, 2020		December 31, 2019
CURRENT LIABILITIES				
Accounts Payable	$	1,659.6	$	2,085.8
Short-term Debt:				
Securitized Debt for Receivables – AEP Credit		703.0		710.0
Other Short-term Debt		1,694.0		2,128.3
Total Short-term Debt		2,397.0		2,838.3
Long-term Debt Due Within One Year (September 30, 2020 and December 31, 2019 Amounts Include $176.6 and $565.1, Respectively, Related to Transition Funding, DCC Fuel, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)		1,911.6		1,598.7
Risk Management Liabilities		62.4		114.3
Customer Deposits		339.7		366.1
Accrued Taxes		942.7		1,357.8
Accrued Interest		331.0		243.6
Obligations Under Operating Leases		236.5		234.1
Regulatory Liability for Over-Recovered Fuel Costs		82.5		86.6
Other Current Liabilities		1,084.2		1,373.8
TOTAL CURRENT LIABILITIES		9,047.2		10,299.1
NONCURRENT LIABILITIES				
Long-term Debt (September 30, 2020 and December 31, 2019 Amounts Include $958.7 and $907, Respectively, Related to Transition Funding, DCC Fuel, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)		28,155.5		25,126.8
Long-term Risk Management Liabilities		232.4		261.8
Deferred Income Taxes		8,011.4		7,588.2
Regulatory Liabilities and Deferred Investment Tax Credits		8,249.2		8,457.6
Asset Retirement Obligations		2,448.3		2,216.6
Employee Benefits and Pension Obligations		353.1		466.0
Obligations Under Operating Leases		690.5		734.6
Deferred Credits and Other Noncurrent Liabilities		794.6		719.8
TOTAL NONCURRENT LIABILITIES		48,935.0		45,571.4
TOTAL LIABILITIES		57,982.2		55,870.5
Rate Matters (Note 4)				
Commitments and Contingencies (Note 5)				
MEZZANINE EQUITY				
Redeemable Noncontrolling Interest		—		65.7
Contingently Redeemable Performance Share Awards		72.5		42.9
TOTAL MEZZANINE EQUITY		72.5		108.6
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				

	2020	2019
Shares Authorized	600,000,000	600,000,000
Shares Issued	516,551,408	514,373,631

		September 30, 2020		December 31, 2019
(20,204,160 Shares were Held in Treasury as of September 30, 2020 and December 31, 2019, Respectively)		3,357.6		3,343.4
Paid-in Capital		6,522.3		6,535.6
Retained Earnings		10,621.4		9,900.9
Accumulated Other Comprehensive Income (Loss)		(135.4)		(147.7)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY		20,365.9		19,632.2
Noncontrolling Interests		268.7		281.0
TOTAL EQUITY		20,634.6		19,913.2
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY	$	78,689.3	$	75,892.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2020	2019
OPERATING ACTIVITIES		
Net Income	$ 1,762.0	$ 1,767.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,996.3	1,873.6
Deferred Income Taxes	142.5	15.9
Allowance for Equity Funds Used During Construction	(111.7)	(122.3)
Mark-to-Market of Risk Management Contracts	46.4	(41.6)
Amortization of Nuclear Fuel	67.2	71.6
Pension Contributions to Qualified Plan Trust	(110.3)	—
Property Taxes	396.9	341.7
Deferred Fuel Over/Under-Recovery, Net	27.4	93.7
Recovery of Ohio Capacity Costs	—	34.1
Refund of Global Settlement	—	(12.4)
Change in Other Noncurrent Assets	(219.6)	(9.6)
Change in Other Noncurrent Liabilities	(25.1)	(16.3)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(138.9)	125.0
Fuel, Materials and Supplies	(97.4)	(116.6)
Accounts Payable	21.9	(32.4)
Accrued Taxes, Net	(502.9)	(359.9)
Other Current Assets	26.0	60.2
Other Current Liabilities	(358.5)	(321.9)
Net Cash Flows from Operating Activities	2,922.2	3,349.9
INVESTING ACTIVITIES		
Construction Expenditures	(4,690.4)	(4,336.0)
Purchases of Investment Securities	(1,329.5)	(951.5)
Sales of Investment Securities	1,293.0	874.2
Acquisitions of Nuclear Fuel	(68.4)	(91.9)
Acquisition of Sempra Renewables LLC and Santa Rita East, Net of Cash and Restricted Cash Acquired	—	(921.3)
Other Investing Activities	88.0	68.9
Net Cash Flows Used for Investing Activities	(4,707.3)	(5,357.6)
FINANCING ACTIVITIES		
Issuance of Common Stock	136.5	44.7
Issuance of Long-term Debt	3,985.8	3,492.4
Issuance of Short-term Debt with Original Maturities greater than 90 Days	1,304.5	—
Change in Short-term Debt with Original Maturities less than 90 Days, Net	(1,445.8)	600.0
Retirement of Long-term Debt	(700.5)	(1,023.5)
Make Whole Premium on Extinguishment of Long-term Debt	—	(5.0)
Redemption of Short-term Debt with Original Maturities Greater than 90 Days	(300.0)	—
Principal Payments for Finance Lease Obligations	(46.3)	(44.5)
Dividends Paid on Common Stock	(1,055.7)	(1,002.0)
Redemption of Noncontrolling Interest in Trent and Desert Sky Windfarms	(56.5)	—
Other Financing Activities	(5.7)	(8.7)
Net Cash Flows from Financing Activities	1,816.3	2,053.4
Net Increase in Cash, Cash Equivalents and Restricted Cash	31.2	45.7
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	432.6	444.1
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 463.8	$ 489.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 690.5	$ 689.7
Net Cash Paid (Received) for Income Taxes	(23.9)	22.8
Noncash Acquisitions Under Finance Leases	33.0	66.7
Construction Expenditures Included in Current Liabilities as of September 30,	830.1	1,018.9
Construction Expenditures Included in Noncurrent Liabilities as of September 30,	8.3	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	1.0	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	2.4	—
Noncontrolling Interest assumed with Sempra Renewable LLC and Santa Rita East Acquisition	—	253.4
Liabilities assumed with Sempra Renewable LLC and Santa Rita East Acquisition	—	32.4
Forward Equity Purchase Contract Included in Current and Noncurrent Liabilities as of September 30,	120.6	52.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions of KWhs)			
Retail:				
Residential	4,112	4,148	9,736	9,580
Commercial	2,941	3,152	7,700	7,997
Industrial	2,037	2,168	6,618	6,556
Miscellaneous	184	197	486	512
Total Retail	9,274	9,665	24,540	24,645

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in degree days)			
Actual – Heating (a)	1	—	98	180
Normal – Heating (b)	—	—	188	190
Actual – Cooling (c)	1,357	1,587	2,524	2,679
Normal – Cooling (b)	1,378	1,368	2,436	2,425

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

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Net Income
(in millions)

Third Quarter of 2019	$	77.0
Changes in Gross Margin:		
Retail Margins		(1.4)
Margins from Off-system Sales		(0.4)
Transmission Revenues		4.3
Other Revenues		(59.0)
Total Change in Gross Margin		(56.5)
Changes in Expenses and Other:		
Other Operation and Maintenance		(4.8)
Depreciation and Amortization		62.5
Taxes Other Than Income Taxes		1.1
Interest Income		0.1
Allowance for Equity Funds Used During Construction		(0.7)
Interest Expense		(8.7)
Total Change in Expenses and Other		49.5
Income Tax Expense		12.6
Third Quarter of 2020	$	82.6

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

- **Retail Margins** decreased $1 million primarily due to the following:
  - A $19 million decrease due to refunds of Excess ADIT and excess federal income taxes collected as a result of Tax Reform. This decrease was partially offset in Income Tax Expense below.
  - An $11 million decrease in weather-related usage primarily due to a 14% decrease in cooling degree days.
  - A $3 million decrease due to refunds to customers associated with the most recent base rate case. This decrease was offset in Other Revenues below.

  These decreases were partially offset by:
  - A $19 million increase in weather-normalized margins primarily in the residential class.
  - A $6 million increase from interim rate increases driven by increased distribution investment.
  - A $5 million increase due to new base rates implemented in June 2020.
- **Transmission Revenues** increased $4 million primarily due to:
  - An $11 million increase from interim rate increases driven by increased transmission investment.

  This increase was partially offset by:
  - A $7 million decrease due to refunds to customers associated with the most recent base rate case. This decrease was offset in Other Revenues below.
- **Other Revenues** decreased $59 million primarily due to the following:
  - A $68 million decrease in securitization revenues primarily due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset below in Depreciation and Amortization expenses and in Interest Expense.

  This decrease was partially offset by:
  - An $8 million increase in revenues due to the amortization of a provision for refund recorded in December 2019 as part of the most recent base rate case. This increase was partially offset in Retail Margins and Transmission Revenues above.

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

- **Other Operation and Maintenance** expenses increased $5 million primarily due to the following:
  - A $5 million increase due to the write-off of land associated with the Oklaunion Power Station.
  - A $4 million increase in transmission expenses. This increase was partially offset in Gross Margin above.

  These increases were partially offset by:
  - A $3 million decrease in distribution expenses.
- **Depreciation and Amortization** expenses decreased $63 million primarily due to a decrease in securitization amortizations due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 202. This decrease was offset in Other Revenues above and in Interest Expense below.
- **Interest Expense** increased $9 million primarily due to the following:
  - A $5 million increase due to higher long-term debt balances.
  - A $3 million increase due to the prior year 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.
- **Income Tax Expense** decreased $13 million primarily due to an increase in amortization of Excess ADIT and the recognition of a discrete tax adjustment in 2020 which was primarily attributable to the 5-year net operating loss carryback provision of the CARES Act.This decrease was partially offset above in Gross Margins and in Other Operation and Maintenance expenses.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Net Income
(in millions)

Nine Months Ended September 30, 2019	$	192.0
Changes in Gross Margin:		
Retail Margins		2.7
Margins from Off-system Sales		(20.2)
Transmission Revenues		8.9
Other Revenues		(36.8)
Total Change in Gross Margin		(45.4)
Changes in Expenses and Other:		
Other Operation and Maintenance		77.3
Depreciation and Amortization		29.0
Taxes Other Than Income Taxes		3.6
Interest Income		(0.3)
Allowance for Equity Funds Used During Construction		6.1
Interest Expense		(36.5)
Total Change in Expenses and Other		79.2
Income Tax Expense		(28.7)
Nine Months Ended September 30, 2020	$	197.1

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

- **Retail Margins** increased $3 million primarily due to the following:
  - A $21 million increase in weather-normalized margins primarily driven by the residential class and partially offset by a decrease in the industrial class.
  - A $7 million increase from interim rate increases driven by increased transmission investment.
  - A $7 million increase from interim rate increases driven by increased distribution investment.
  - A $7 million increase due to new base rates implemented in June 2020.
  - A $5 million increase due to the change in the recording of merger savings as authorized by the PUCT in the most recent base rate case.

  These increases were partially offset by:
  - A $25 million decrease due to refunds of Excess ADIT and excess federal income taxes collected as a result of Tax Reform. This decrease was partially offset in Income Tax Expense below.
  - A $15 million decrease in weather-related usage primarily due to a 6% decrease in cooling degree days and a 46% decrease in heating degree days.
  - A $4 million decrease due to refunds to customers associated with the most recent base rate case. This decrease was offset in Other Revenues below.
- **Margins from Off-system Sales** decreased $20 million primarily due to lower Oklaunion Power Station PPA revenues. This decrease was partially offset in Other Operation and Maintenance expenses below.
- **Transmission Revenues** increased $9 million primarily due to the following:
  - A $30 million increase from interim rate increases driven by increased transmission investment.

  This increase was partially offset by:
  - A $14 million decrease due to a one-time credit to transmission customers as a result of Tax Reform and the most recent base rate case. This decrease was offset in Income Tax Expense below.
  - A $7 million decrease due to refunds to customers associated with the most recent base rate case. This decrease was offset in Other Revenues below.

- **Other Revenues** decreased $37 million primarily due to the following:
  - A $49 million decrease related to securitization revenues primarily due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This decrease was offset below in Depreciation and Amortization expenses and in Interest Expense.

  This decrease was partially offset by:
  - An $11 million increase in revenues due to the amortization of a provision for refund recorded in December 2019 as part of the most recent base rate case. This increase was offset in Retail Margins and Transmission Revenues above.

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

Other Operation and Maintenance expenses decreased $77 million primarily due to the following:
  - A $67 million decrease due to prior year partial amortization of the AEP Texas Storm Restoration Securitization regulatory asset as a result of the AEP Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.This decrease was offset in Income Tax Expense below.
  - A $17 million decrease due to the revision of the Oklaunion Power Station ARO.This decrease was offset in Margins from Off-System Sales above.

  These decreases were partially offset by:
  - A $9 million increase in transmission expenses. This increase was partially offset in Gross Margin above.
  - A $5 million increase due to the write-off of land associated with the Oklaunion Power Station.
- **Depreciation and Amortization** expenses decreased $29 million primarily due to the following:
  - A $43 million decrease in securitization amortizations due to the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020. This increase was offset in Other Revenues above and in Interest Expense below.

  This decrease was partially offset by:
  - A $14 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- **Taxes Other Than Income Taxes** decreased $4 million primarily due to lower property taxes.
- **Allowance for Equity Funds Used During Construction**increased $6 million primarily due to an increase in the equity component of AFUDC as a result of lower short-term balances and increased transmission projects.
- **Interest Expense** increased $37 million primarily due to:
  - A $24 million increase due to the prior year 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 $9 million increase due to higher long-term debt balances.
  - A $6 million increase due to due to a decrease in the debt component of AFUDC.

  These increases were partially offset by:
  - A $5 million decrease due to lower short-term debt balances.
- **Income Tax Expense** increased $29 million primarily due to the prior year amortization of Excess ADIT not subject to normalization requirements as approved in the Texas Storm Cost Securitization financing order issued by the PUCT in 2019 partially offset by current year amortization of Excess ADIT and an increase in favorable AFUDC Equity tax benefit.This increase was partially offset in Gross Margins and Other Operation and Maintenance Expenses above.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
REVENUES				
Electric Transmission and Distribution	$ 390.1	$ 445.4	$ 1,165.2	$ 1,190.3
Sales to AEP Affiliates	41.4	42.7	89.4	125.1
Other Revenues	0.5	1.2	2.5	2.6
TOTAL REVENUES	432.0	489.3	1,257.1	1,318.0
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	10.4	11.2	13.6	29.1
Other Operation	134.3	128.2	344.7	349.2
Maintenance	20.4	21.7	64.1	136.9
Depreciation and Amortization	107.7	170.2	435.8	464.8
Taxes Other Than Income Taxes	38.7	39.8	106.7	110.3
TOTAL EXPENSES	311.5	371.1	964.9	1,090.3
OPERATING INCOME	120.5	118.2	292.2	227.7
Other Income (Expense):				
Interest Income	0.5	0.4	1.2	1.5
Allowance for Equity Funds Used During Construction	4.4	5.1	14.4	8.3
Non-Service Cost Components of Net Periodic Benefit Cost	2.8	2.8	8.4	8.4
Interest Expense	(44.5)	(35.8)	(129.2)	(92.7)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	83.7	90.7	187.0	153.2
Income Tax Expense (Benefit)	1.1	13.7	(10.1)	(38.8)
NET INCOME	$ 82.6	$ 77.0	$ 197.1	$ 192.0

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
Net Income	$ 82.6	$ 77.0	$ 197.1	$ 192.0
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2020 and 2019, Respectively, and $0.2 and $0.2 for the Nine Months Ended September 30, 2020 and 2019, Respectively	0.3	0.3	0.8	0.8
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2020 and 2019, Respectively, and $0 and $0 for the Nine Months Ended September 30, 2020 and 2019, Respectively	—	—	0.1	0.1
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.3	0.9	0.9
TOTAL COMPREHENSIVE INCOME	$ 82.9	$ 77.3	$ 198.0	$ 192.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 1,257.9	$ 1,337.7	$ (15.1)	$ 2,580.5
Capital Contribution from Parent	200.0			200.0
Net Income		34.4		34.4
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	1,457.9	1,372.1	(14.8)	2,815.2
Net Income		80.6		80.6
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	1,457.9	1,452.7	(14.5)	2,896.1
Net Income		77.0		77.0
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2019	$ 1,457.9	$ 1,529.7	$ (14.2)	$ 2,973.4
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 1,457.9	$ 1,516.0	$ (12.8)	$ 2,961.1
Net Income		47.6		47.6
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2020	1,457.9	1,563.6	(12.5)	3,009.0
Net Income		66.9		66.9
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2020	1,457.9	1,630.5	(12.2)	3,076.2
Net Income		82.6		82.6
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2020	$ 1,457.9	$ 1,713.1	$ (11.9)	$ 3,159.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 0.1	$ 3.1
Restricted Cash (September 30, 2020 and December 31, 2019 Amounts Include $44.8 and $154.7, Respectively, Related to Transition Funding and Restoration Funding)	44.8	154.7
Advances to Affiliates	148.4	207.2
Accounts Receivable:		
Customers	136.8	116.0
Affiliated Companies	22.0	10.1
Accrued Unbilled Revenues	74.8	68.8
Miscellaneous	—	0.3
Allowance for Uncollectible Accounts	—	(1.8)
Total Accounts Receivable	233.6	193.4
Fuel	—	5.9
Materials and Supplies	72.0	56.7
Accrued Tax Benefits	9.6	66.1
Prepayments and Other Current Assets	5.6	5.8
TOTAL CURRENT ASSETS	514.1	692.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	—	351.7
Transmission	4,943.8	4,466.5
Distribution	4,486.6	4,215.2
Other Property, Plant and Equipment	868.2	805.9
Construction Work in Progress	787.9	763.9
Total Property, Plant and Equipment	11,086.5	10,603.2
Accumulated Depreciation and Amortization	1,541.5	1,758.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,545.0	8,845.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	275.4	280.6
Securitized Assets (September 30, 2020 and December 31, 2019 Amounts Include $467.8 and $621.2, Respectively, Related to Transition Funding and Restoration Funding)	467.8	623.4
Deferred Charges and Other Noncurrent Assets	182.7	147.1
TOTAL OTHER NONCURRENT ASSETS	925.9	1,051.1
TOTAL ASSETS	$ 10,985.0	$ 10,589.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 235.3	$ 256.8
Affiliated Companies	27.2	35.6
Short-term Debt – Nonaffiliated	2.0	—
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2020 and December 31, 2019 Amounts Include $87.7 and $281.4, Respectively, Related to Transition Funding and Restoration Funding)	87.8	392.1
Risk Management Liabilities	0.1	—
Accrued Taxes	101.8	84.9
Accrued Interest (September 30, 2020 and December 31, 2019 Amounts Include $3.5 and $7.5, Respectively, Related to Transition Funding and Restoration Funding)	54.7	35.7
Oklaunion Purchase Power Agreement	—	22.1
Obligations Under Operating Leases	13.7	12.0
Provision for Refund	31.6	64.7
Other Current Liabilities	92.2	123.3
TOTAL CURRENT LIABILITIES	646.4	1,027.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2020 and December 31, 2019 Amounts Include $440.2 and $495.4, Respectively, Related to Transition Funding and Restoration Funding)	4,766.9	4,166.3
Deferred Income Taxes	1,004.4	965.4
Regulatory Liabilities and Deferred Investment Tax Credits	1,282.6	1,316.9
Obligations Under Operating Leases	71.0	71.1
Deferred Credits and Other Noncurrent Liabilities	54.6	81.1
TOTAL NONCURRENT LIABILITIES	7,179.5	6,600.8
TOTAL LIABILITIES	7,825.9	7,628.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	1,457.9	1,457.9
Retained Earnings	1,713.1	1,516.0
Accumulated Other Comprehensive Income (Loss)	(11.9)	(12.8)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,159.1	2,961.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,985.0	$ 10,589.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2020	2019
OPERATING ACTIVITIES		
Net Income	$ 197.1	$ 192.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	435.8	464.8
Deferred Income Taxes	(11.5)	(0.6)
Allowance for Equity Funds Used During Construction	(14.4)	(8.3)
Mark-to-Market of Risk Management Contracts	0.1	0.2
Pension Contributions to Qualified Plan Trust	(11.3)	—
Change in Other Noncurrent Assets	(77.3)	0.5
Change in Other Noncurrent Liabilities	(30.0)	6.5
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(40.2)	(50.0)
Fuel, Materials and Supplies	(9.4)	(0.1)
Accounts Payable	24.2	17.8
Accrued Taxes, Net	73.4	(33.4)
Other Current Assets	(0.8)	(0.7)
Other Current Liabilities	(49.8)	(12.9)
Net Cash Flows from Operating Activities	485.9	575.8
INVESTING ACTIVITIES		
Construction Expenditures	(976.1)	(954.5)
Change in Advances to Affiliates, Net	58.8	0.3
Other Investing Activities	24.1	18.4
Net Cash Flows Used for Investing Activities	(893.2)	(935.8)
FINANCING ACTIVITIES		
Capital Contribution from Parent	—	200.0
Issuance of Long-term Debt – Nonaffiliated	652.8	627.5
Change in Short-term Debt, Net – Nonaffiliated	2.0	—
Change in Advances from Affiliates, Net	—	(141.2)
Retirement of Long-term Debt – Nonaffiliated	(356.5)	(366.8)
Principal Payments for Finance Lease Obligations	(4.7)	(3.8)
Other Financing Activities	0.8	(1.1)
Net Cash Flows from Financing Activities	294.4	314.6
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(112.9)	(45.4)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	157.8	159.8
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 44.9	$ 114.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 102.0	$ 95.1
Net Cash Paid (Received) for Income Taxes	(55.6)	28.7
Noncash Acquisitions Under Finance Leases	5.1	6.9
Construction Expenditures Included in Current Liabilities as of September 30,	167.6	183.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of September 30, 2020	As of September 30, 2019
	(in millions)	
Plant In Service	$ 9,240.4	$ 7,409.0
Construction Work in Progress	1,680.9	1,858.4
Accumulated Depreciation and Amortization	531.8	368.8
Total Transmission Property, Net	$ 10,389.5	$ 8,898.6

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Net Income
(in millions)

Third Quarter of 2019	$ 107.6
Changes in Transmission Revenues:	
Transmission Revenues	44.4
Total Change in Transmission Revenues	44.4
Changes in Expenses and Other:	
Other Operation and Maintenance	0.4
Depreciation and Amortization	(16.2)
Taxes Other Than Income Taxes	(9.3)
Interest Income	(0.6)
Allowance for Equity Funds Used During Construction	(0.8)
Interest Expense	(6.3)
Total Change in Expenses and Other	(32.8)
Income Tax Expense	(1.6)
Third Quarter of 2020	$ 117.6

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

- **Transmission Revenues** increased $44 million primarily due to continued investment in transmission assets.

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

- **Depreciation and Amortization** expenses increased $16 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $9 million primarily due to higher property taxes as a result of increased transmission investment.
- **Interest Expense** increased $6 million primarily due to higher long-term debt balances.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Net Income
(in millions)

Nine Months Ended September 30, 2019	$	347.9
Changes in Transmission Revenues:		
Transmission Revenues		67.7
Total Change in Transmission Revenues		67.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(8.2)
Depreciation and Amortization		(48.0)
Taxes Other Than Income Taxes		(26.6)
Interest Income		0.2
Allowance for Equity Funds Used During Construction		(6.2)
Interest Expense		(25.6)
Total Change in Expenses and Other		(114.4)
Income Tax Expense		7.9
Nine Months Ended September 30, 2020	$	309.1

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

- **Transmission Revenues** increased $68 million primarily due to the following:
  - A $147 million increase due to continued investment in transmission assets.

    This increase was partially offset by:
  - A $62 million decrease as a result of the affiliated annual transmission formula rate true-up which is offset in Other Operation and Maintenance expense across the other Registrant subsidiaries.
  - A $17 million decrease as a result of the non-affiliated annual transmission formula rate true-up.

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

- **Other Operation and Maintenance** expenses increased $8 million primarily due to the following:
  - A $5 million increase in rent expense.
  - A $3 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $48 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $27 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** decreased $6 million primarily due to the following:
  - A $12 million decrease driven by the favorable impact of a FERC settlement agreement recorded in 2019.
  - An $8 million decrease due to lower CWIP.

  These decreases were partially offset by:
  - A $13 million increase driven by FERC audit findings recorded in 2019.
- **Interest Expense** increased $26 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $8 million primarily due to lower pretax book income, partially offset by the recognition of a discrete tax adjustment in 2019.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
REVENUES				
Transmission Revenues	$ 62.9	$ 54.0	$ 184.6	$ 162.1
Sales to AEP Affiliates	241.2	205.7	652.6	608.0
Other Revenues	—	—	0.6	—
TOTAL REVENUES	304.1	259.7	837.8	770.1
EXPENSES				
Other Operation	25.3	26.0	72.0	61.7
Maintenance	3.5	3.2	6.8	8.9
Depreciation and Amortization	61.5	45.3	176.4	128.4
Taxes Other Than Income Taxes	52.2	42.9	152.8	126.2
TOTAL EXPENSES	142.5	117.4	408.0	325.2
OPERATING INCOME	161.6	142.3	429.8	444.9
Other Income (Expense):				
Interest Income - Affiliated	0.2	0.8	2.3	2.1
Allowance for Equity Funds Used During Construction	20.2	21.0	54.9	61.1
Interest Expense	(32.7)	(26.4)	(95.1)	(69.5)
INCOME BEFORE INCOME TAX EXPENSE	149.3	137.7	391.9	438.6
Income Tax Expense	31.7	30.1	82.8	90.7
NET INCOME	$ 117.6	$ 107.6	$ 309.1	$ 347.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2018	$ 2,480.6	$ 1,089.2	$ 3,569.8
Net Income		104.3	104.3
TOTAL MEMBER'S EQUITY – MARCH 31, 2019	2,480.6	1,193.5	3,674.1
Net Income		136.0	136.0
TOTAL MEMBER'S EQUITY – JUNE 30, 2019	2,480.6	1,329.5	3,810.1
Net Income		107.6	107.6
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2019	$ 2,480.6	$ 1,437.1	$ 3,917.7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2019	$ 2,480.6	$ 1,528.9	$ 4,009.5
Capital Contribution from Member	185.0		185.0
Net Income		117.8	117.8
TOTAL MEMBER'S EQUITY – MARCH 31, 2020	2,665.6	1,646.7	4,312.3
Dividends Paid to AEP Transmission Holdco		(5.0)	(5.0)
Net Income		73.7	73.7
TOTAL MEMBER'S EQUITY – JUNE 30, 2020	2,665.6	1,715.4	4,381.0
Net Income		117.6	117.6
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2020	$ 2,665.6	$ 1,833.0	$ 4,498.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

	September 30, 2020		December 31, 2019	
CURRENT ASSETS				
Advances to Affiliates	$	106.7	$	85.4
Accounts Receivable:				
Customers		34.1		19.0
Affiliated Companies		81.1		66.1
Total Accounts Receivable		115.2		85.1
Materials and Supplies		13.6		13.8
Prepayments and Other Current Assets		5.3		13.1
TOTAL CURRENT ASSETS		240.8		197.4
TRANSMISSION PROPERTY				
Transmission Property		8,947.4		8,137.9
Other Property, Plant and Equipment		293.0		269.6
Construction Work in Progress		1,680.9		1,485.7
Total Transmission Property		10,921.3		9,893.2
Accumulated Depreciation and Amortization		531.8		402.3
TOTAL TRANSMISSION PROPERTY – NET		10,389.5		9,490.9
OTHER NONCURRENT ASSETS				
Regulatory Assets		6.8		4.2
Deferred Property Taxes		57.2		193.5
Deferred Charges and Other Noncurrent Assets		4.4		4.8
TOTAL OTHER NONCURRENT ASSETS		68.4		202.5
TOTAL ASSETS	$	10,698.7	$	9,890.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT LIABILITIES		
Advances from Affiliates	$ 86.8	$ 137.0
Accounts Payable:		
General	337.7	493.4
Affiliated Companies	62.4	71.2
Accrued Taxes	216.6	355.6
Accrued Interest	48.2	19.2
Obligations Under Operating Leases	2.3	2.1
Other Current Liabilities	9.1	14.6
TOTAL CURRENT LIABILITIES	763.1	1,093.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,947.9	3,427.3
Deferred Income Taxes	892.6	817.8
Regulatory Liabilities	575.2	540.9
Obligations Under Operating Leases	1.4	1.9
Deferred Credits and Other Noncurrent Liabilities	19.9	0.3
TOTAL NONCURRENT LIABILITIES	5,437.0	4,788.2
TOTAL LIABILITIES	6,200.1	5,881.3
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	2,665.6	2,480.6
Retained Earnings	1,833.0	1,528.9
TOTAL MEMBER'S EQUITY	4,498.6	4,009.5
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 10,698.7	$ 9,890.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Nine Months Ended September 30,			
		2020		2019
OPERATING ACTIVITIES				
Net Income	$	309.1	$	347.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization		176.4		128.4
Deferred Income Taxes		65.4		36.7
Allowance for Equity Funds Used During Construction		(54.9)		(61.1)
Property Taxes		136.3		110.7
Change in Other Noncurrent Assets		(1.5)		1.0
Change in Other Noncurrent Liabilities		19.5		(3.8)
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net		(30.1)		(5.1)
Materials and Supplies		0.2		3.9
Accounts Payable		26.0		4.1
Accrued Taxes, Net		(139.0)		(92.8)
Accrued Interest		29.0		23.8
Other Current Assets		9.1		(1.0)
Other Current Liabilities		(10.7)		(8.5)
Net Cash Flows from Operating Activities		534.8		484.2
INVESTING ACTIVITIES				
Construction Expenditures		(1,163.8)		(959.9)
Change in Advances to Affiliates, Net		(21.3)		(178.3)
Acquisitions of Assets		(3.6)		(7.6)
Other Investing Activities		4.7		12.0
Net Cash Flows Used for Investing Activities		(1,184.0)		(1,133.8)
FINANCING ACTIVITIES				
Capital Contributions from Member		185.0		—
Issuance of Long-term Debt – Nonaffiliated		519.4		685.9
Change in Advances from Affiliates, Net		(50.2)		(36.3)
Dividends Paid to AEP Transmission Holdco		(5.0)		—
Net Cash Flows from Financing Activities		649.2		649.6
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	$	63.3	$	43.0
Net Cash Paid for Income Taxes		1.9		29.8
Construction Expenditures Included in Current Liabilities as of September 30,		283.6		315.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
	(in millions of KWhs)			
Retail:				
Residential	2,772	2,728	8,229	8,401
Commercial	1,612	1,721	4,410	4,812
Industrial	2,193	2,487	6,507	7,180
Miscellaneous	203	216	585	640
Total Retail	6,780	7,152	19,731	21,033
Wholesale	1,187	938	2,894	2,667
Total KWhs	7,967	8,090	22,625	23,700

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
	(in degree days)			
Actual – Heating (a)	1	—	1,098	1,295
Normal – Heating (b)	2	3	1,413	1,407
Actual – Cooling (c)	988	1,071	1,354	1,530
Normal – Cooling (b)	825	815	1,208	1,194

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

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Net Income
(in millions)

Third Quarter of 2019	$	104.3
Changes in Gross Margin:		
Retail Margins		7.9
Margins from Off-system Sales		(1.2)
Transmission Revenues		(3.1)
Other Revenues		(1.3)
Total Change in Gross Margin		2.3
Changes in Expenses and Other:		
Other Operation and Maintenance		13.6
Depreciation and Amortization		(4.5)
Taxes Other Than Income Taxes		(2.1)
Interest Income		0.3
Allowance for Equity Funds Used During Construction		1.9
Non-Service Cost Components of Net Periodic Benefit Cost		0.4
Interest Expense		(3.4)
Total Change in Expenses and Other		6.2
Income Tax Expense (Benefit)		3.8
Third Quarter of 2020	$	116.6

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

- **Retail Margins** increased $8 million primarily due to the following:
  - An $8 million increase in deferred fuel primarily due to the timing of recoverable PJM expenses.This increase was offset in other expense items below.
  - A $6 million increase due to a decrease in customer refunds related to Tax Reform. This increase was partially offset in Income Tax Expense below.
  - A $4 million increase due to the WVPSC approval of the Mitchell Plant surcharge effective January 2020.

  These increases were partially offset by:
  - An $8 million decrease in weather-related usage primarily driven by an 8% decrease in cooling degree days.
  - A $3 million decrease in weather-normalized margins primarily in the commercial and industrial classes, partially offset in the residential class.
- **Transmission Revenue** decreased $3 million primarily due to an adjustment in July 2019 to the annual transmission formula rate true-up.

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

- **Other Operation and Maintenance** expenses decreased $14 million primarily due to the following:
  - A $6 million decrease in distribution expense primarily due to storm and vegetation management expenses.
  - A $3 million decrease in PJM expenses primarily related to the annual transmission formula rate true-up.
  - A $3 million decrease in maintenance expense at various generation plants.
  - A $2 million decrease in uncollectible accounts expenses.

  These decreases were partially offset by:
  - A $4 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $5 million primarily due to a higher depreciable base.

- **Interest Expense** increased $3 million primarily due to higher long-term debt balances.
- **Income Tax Expense (Benefit)** decreased $4 million primarily due the recognition of a discrete tax adjustment, which was primarily attributable to the filing of the 2019 Federal Income Tax return in the third quarter of 2020, and an increase in parent company loss benefit, partially offset by a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT is partially offset above in Gross Margin and Other Operation and Maintenance expenses.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Net Income
(in millions)

Nine Months Ended September 30, 2019	$	293.5
Changes in Gross Margin:		
Retail Margins		35.7
Margins from Off-system Sales		(3.2)
Transmission Revenues		(8.9)
Other Revenues		(1.3)
Total Change in Gross Margin		22.3
Changes in Expenses and Other:		
Other Operation and Maintenance		72.7
Depreciation and Amortization		(17.7)
Taxes Other Than Income Taxes		(5.7)
Interest Income		(0.7)
Allowance for Equity Funds Used During Construction		(1.0)
Non-Service Cost Components of Net Periodic Benefit Cost		1.3
Interest Expense		(9.7)
Total Change in Expenses and Other		39.2
Income Tax Expense (Benefit)		(41.8)
Nine Months Ended September 30, 2020	$	313.2

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 $36 million primarily due to the following:
  - A $30 million increase due to a decrease in customer refunds related to Tax Reform. This increase was partially offset in Income Tax Expense below.
  - A $28 million increase in deferred fuel primarily due to the timing of recoverable PJM expenses offset in line items below.
  - A $12 million increase due to the WVPSC approval of the Mitchell Plant surcharge effective January 2020. Pursuant to the WVPSC approval of the surcharge, this increase was partially offset by the amortization of Excess ADIT not subject to normalization requirements in Income Tax Expense below.
  - A $12 million increase due to the impact of the 2019 WVPSC order which required APCo to offset Excess ADIT not subject to normalization requirements against the deferred fuel under-recovery balance in 2019.
  - An $11 million increase due to a base rate increase in West Virginia.

  These increases were partially offset by:
  - A $41 million decrease in weather-related usage primarily driven by a 15% decrease in heating degree days and a 12% decrease in cooling degree days.
  - A $16 million decrease in weather-normalized margins primarily in the commercial and industrial classes, partially offset in the residential class.
- **Margins from Off-system Sales** decreased $3 million due to weaker market prices for energy in the RTOs which caused a decrease in sales volume and margins.
- **Transmission Revenues** decreased $9 million primarily due to the following:
  - A $13 million decrease from the annual transmission formula rate true-up.

  This decrease was partially offset by:
  - A $4 million increase from investment in transmission assets.

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

- **Other Operation and Maintenance** expenses decreased $73 million primarily due to the following:
  - A $17 million decrease in transmission expenses primarily related to the annual transmission formula rate true-up.
  - A $20 million decrease in maintenance expense at various generation plants.
  - A $14 million decrease as a result of prior year contributions to benefit low income West Virginia residential customers as a result of the West Virginia Tax Reform settlement. This decrease was offset in Income Tax Expense below.
  - A $10 million decrease in distribution expense primarily due to storm and vegetation management expenses.
  - An $8 million decrease in employee-related expenses.
- **Depreciation and Amortization** expenses increased $18 million primarily due to a higher depreciable base and an increase in West Virginia depreciation rates beginning in March 2019. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to the following:
  - A $3 million increase in property taxes due to additional investments in utility plant.
  - A $3 million increase in state business and occupation taxes due to the reduction of the revitalization tax credit.
- **Interest Expense** increased $10 million primarily due to higher long-term debt balances.
- **Income Tax Expense (Benefit)** increased $42 million primarily due to a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT is partially offset above in Gross Margin and Other Operation and Maintenance expenses.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
REVENUES				
Electric Generation, Transmission and Distribution	$ 688.9	$ 696.7	$ 1,989.9	$ 2,041.3
Sales to AEP Affiliates	44.4	56.6	124.9	154.6
Other Revenues	2.4	2.2	7.8	8.2
TOTAL REVENUES	735.7	755.5	2,122.6	2,204.1
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	166.0	177.3	430.9	521.8
Purchased Electricity for Resale	67.5	78.3	240.5	253.4
Other Operation	136.3	140.4	379.1	416.2
Maintenance	52.0	61.5	148.7	184.3
Depreciation and Amortization	123.2	118.7	366.0	348.3
Taxes Other Than Income Taxes	38.8	36.7	114.2	108.5
TOTAL EXPENSES	583.8	612.9	1,679.4	1,832.5
OPERATING INCOME	151.9	142.6	443.2	371.6
Other Income (Expense):				
Interest Income	0.6	0.3	1.4	2.1
Allowance for Equity Funds Used During Construction	6.7	4.8	11.5	12.5
Non-Service Cost Components of Net Periodic Benefit Cost	4.7	4.3	14.1	12.8
Interest Expense	(55.0)	(51.6)	(162.2)	(152.5)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	108.9	100.4	308.0	246.5
Income Tax Expense (Benefit)	(7.7)	(3.9)	(5.2)	(47.0)
NET INCOME	$ 116.6	$ 104.3	$ 313.2	$ 293.5

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Net Income	$ 116.6	$ 104.3	$ 313.2	$ 293.5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $(0.1) for the Three Months Ended September 30, 2020 and 2019, Respectively, and $(1.2) and $(0.2) for the Nine Months Ended September 30, 2020 and 2019, Respectively	0.6	(0.3)	(4.4)	(0.7)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.3) and $(0.2) for the Three Months Ended September 30, 2020 and 2019, Respectively, and $(0.8) and $(0.5) for the Nine Months Ended September 30, 2020 and 2019, Respectively	(0.9)	(0.6)	(2.8)	(1.9)
TOTAL OTHER COMPREHENSIVE LOSS	(0.3)	(0.9)	(7.2)	(2.6)
TOTAL COMPREHENSIVE INCOME	$ 116.3	$ 103.4	$ 306.0	$ 290.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2018	$ 260.4	$ 1,828.7	$ 1,922.0	$ (5.0)	$ 4,006.1
Common Stock Dividends			(50.0)		(50.0)
Net Income			133.7		133.7
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2019	260.4	1,828.7	2,005.7	(5.8)	4,089.0
Common Stock Dividends			(50.0)		(50.0)
Net Income			55.5		55.5
Other Comprehensive Loss				(0.9)	(0.9)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2019	260.4	1,828.7	2,011.2	(6.7)	4,093.6
Common Stock Dividends			(25.0)		(25.0)
Net Income			104.3		104.3
Other Comprehensive Loss				(0.9)	(0.9)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2019	$ 260.4	$ 1,828.7	$ 2,090.5	$ (7.6)	$ 4,172.0
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2019	$ 260.4	$ 1,828.7	$ 2,078.3	$ 5.0	$ 4,172.4
Common Stock Dividends			(50.0)		(50.0)
Net Income			115.3		115.3
Other Comprehensive Loss				(5.1)	(5.1)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2020	260.4	1,828.7	2,143.6	(0.1)	4,232.6
Common Stock Dividends			(50.0)		(50.0)
Net Income			81.3		81.3
Other Comprehensive Loss				(1.8)	(1.8)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2020	260.4	1,828.7	2,174.9	(1.9)	4,262.1
Common Stock Dividends			(50.0)		(50.0)
Net Income			116.6		116.6
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2020	$ 260.4	$ 1,828.7	$ 2,241.5	$ (2.2)	$ 4,328.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.9	$ 3.3
Restricted Cash for Securitized Funding	9.3	23.5
Advances to Affiliates	159.5	22.1
Accounts Receivable:		
Customers	136.6	129.0
Affiliated Companies	60.2	64.3
Accrued Unbilled Revenues	52.6	59.7
Miscellaneous	0.2	0.5
Allowance for Uncollectible Accounts	(3.4)	(2.6)
Total Accounts Receivable	246.2	250.9
Fuel	144.4	149.7
Materials and Supplies	98.2	105.2
Risk Management Assets	30.7	39.4
Regulatory Asset for Under-Recovered Fuel Costs	3.7	42.5
Prepayments and Other Current Assets	29.7	64.0
TOTAL CURRENT ASSETS	725.6	700.6
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,615.9	6,563.7
Transmission	3,811.4	3,584.1
Distribution	4,348.8	4,201.7
Other Property, Plant and Equipment	622.5	571.3
Construction Work in Progress	539.9	593.4
Total Property, Plant and Equipment	15,938.5	15,514.2
Accumulated Depreciation and Amortization	4,652.7	4,432.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	11,285.8	11,081.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	659.1	457.2
Securitized Assets	216.2	234.7
Long-term Risk Management Assets	0.1	0.1
Operating Lease Assets	80.3	78.5
Deferred Charges and Other Noncurrent Assets	190.9	215.3
TOTAL OTHER NONCURRENT ASSETS	1,146.6	985.8
TOTAL ASSETS	$ 13,158.0	$ 12,768.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2020 and December 31, 2019
(Unaudited)

	September 30, 2020	December 31, 2019
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 4.3	$ 236.7
Accounts Payable:		
General	191.6	307.8
Affiliated Companies	80.0	92.5
Long-term Debt Due Within One Year – Nonaffiliated	518.3	215.6
Risk Management Liabilities	5.6	1.9
Customer Deposits	80.1	85.8
Accrued Taxes	77.3	99.6
Accrued Interest	73.8	47.9
Obligations Under Operating Leases	14.7	15.2
Other Current Liabilities	98.4	123.0
TOTAL CURRENT LIABILITIES	1,144.1	1,226.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,315.0	4,148.2
Long-term Risk Management Liabilities	0.2	—
Deferred Income Taxes	1,716.5	1,680.8
Regulatory Liabilities and Deferred Investment Tax Credits	1,195.8	1,268.7
Asset Retirement Obligations	298.2	102.1
Employee Benefits and Pension Obligations	38.2	50.9
Obligations Under Operating Leases	66.1	64.0
Deferred Credits and Other Noncurrent Liabilities	55.5	55.2
TOTAL NONCURRENT LIABILITIES	7,685.5	7,369.9
TOTAL LIABILITIES	8,829.6	8,595.9
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,828.7	1,828.7
Retained Earnings	2,241.5	2,078.3
Accumulated Other Comprehensive Income (Loss)	(2.2)	5.0
TOTAL COMMON SHAREHOLDER'S EQUITY	4,328.4	4,172.4
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 13,158.0	$ 12,768.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2020	**2019**
OPERATING ACTIVITIES		
Net Income	$ 313.2	$ 293.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	366.0	348.3
Deferred Income Taxes	(28.2)	(101.9)
Allowance for Equity Funds Used During Construction	(11.5)	(12.5)
Mark-to-Market of Risk Management Contracts	8.0	2.2
Pension Contributions to Qualified Plan Trust	(7.0)	—
Deferred Fuel Over/Under-Recovery, Net	38.8	60.8
Change in Other Noncurrent Assets	5.4	6.7
Change in Other Noncurrent Liabilities	(26.0)	(29.6)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	7.2	61.7
Fuel, Materials and Supplies	12.4	(49.2)
Accounts Payable	(74.0)	40.1
Accrued Taxes, Net	1.9	(30.2)
Other Current Assets	10.1	6.8
Other Current Liabilities	(9.7)	(25.1)
Net Cash Flows from Operating Activities	606.6	571.6
INVESTING ACTIVITIES		
Construction Expenditures	(566.6)	(607.1)
Change in Advances to Affiliates, Net	(137.4)	0.3
Other Investing Activities	4.6	22.8
Net Cash Flows Used for Investing Activities	(699.4)	(584.0)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	557.2	478.2
Change in Advances from Affiliates, Net	(232.4)	(165.2)
Retirement of Long-term Debt – Nonaffiliated	(90.3)	(180.4)
Principal Payments for Finance Lease Obligations	(5.6)	(5.0)
Dividends Paid on Common Stock	(150.0)	(125.0)
Other Financing Activities	0.3	0.6
Net Cash Flows from Financing Activities	79.2	3.2
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(13.6)	(9.2)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	26.8	29.8
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 13.2	$ 20.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 130.0	$ 120.6
Net Cash Paid (Received) for Income Taxes	(10.7)	58.7
Noncash Acquisitions Under Finance Leases	3.0	7.1
Construction Expenditures Included in Current Liabilities as of September 30,	90.0	134.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
	(in millions of KWhs)			
Retail:				
Residential	1,531	1,496	4,230	4,159
Commercial	1,219	1,312	3,362	3,555
Industrial	1,849	1,937	5,324	5,742
Miscellaneous	14	16	47	49
Total Retail	4,613	4,761	12,963	13,505
Wholesale	1,536	2,398	5,552	6,842
Total KWhs	6,149	7,159	18,515	20,347

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
	(in degree days)			
Actual – Heating (a)	7	—	2,186	2,456
Normal – Heating (b)	10	11	2,429	2,412
Actual – Cooling (c)	637	684	923	917
Normal – Cooling (b)	576	573	841	836

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

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Net Income
(in millions)

Third Quarter of 2019	$	88.8
Changes in Gross Margin:		
Retail Margins		9.0
Margins from Off-system Sales		(0.3)
Transmission Revenues		2.6
Other Revenues		(6.5)
Total Change in Gross Margin		4.8
Changes in Expenses and Other:		
Other Operation and Maintenance		7.1
Depreciation and Amortization		(16.4)
Taxes Other Than Income Taxes		(2.3)
Other Income		(1.3)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.4)
Interest Expense		1.9
Total Change in Expenses and Other		(11.4)
Income Tax Expense		(5.5)
Third Quarter of 2020	$	76.7

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

- **Retail Margins** increased $9 million primarily due to the following:
  - A $38 million increase primarily due to the Indiana and Michigan base rate cases and increases in rate riders. This increase was partially offset in other expense items below.

  This increase was partially offset by:
  - A $20 million decrease in weather-normalized wholesale margins, including the loss of a significant wholesale contract.
  - A $6 million decrease in weather-related usage primarily due to a 7% decrease in cooling degree days.
  - A $3 million decrease in weather-normalized retail margins.
- **Transmission Revenues** increased $3 million primarily due to a July 2019 adjustment to the annual transmission formula rate true-up.
- **Other Revenues** decreased $7 million primarily due to a decrease in barging revenues by River Transportation Division (RTD).This decrease was partially offset in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses decreased $7 million primarily due to the following:
  - A $10 million decrease in nonutility operation expenses primarily due to a decrease in RTD expenses. This decrease was partially offset in Other Revenues above.
  - A $4 million decrease in steam generation expense primarily due to 2019 NSR Consent Decree modifications.
  - A $4 million decrease in nuclear generation expenses primarily due to a decrease in maintenance activities.
  - A $3 million decrease in administrative and general expenses primarily due to a decrease in rate case and insurance expenses.

  These decreases were partially offset by:
  - A $12 million increase in employee-related expenses.
  - A $2 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.

- **Depreciation and Amortization** expenses increased $16 million primarily due to a higher depreciable base and an increase in depreciation rates. This increase was partially offset in Retail Margins above.
- **Income Tax Expense** increased $6 million primarily due to the recognition of a discrete tax adjustment, which was primarily attributable to the filing of the 2019 Federal Income Tax return in the third quarter of 2020, and an increase in state income tax expense.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Net Income
(in millions)

Nine Months Ended September 30, 2019	$	248.0
Changes in Gross Margin:		
Retail Margins		25.8
Margins from Off-system Sales		(0.3)
Transmission Revenues		10.0
Other Revenues		(13.7)
Total Change in Gross Margin		21.8
Changes in Expenses and Other:		
Other Operation and Maintenance		27.4
Depreciation and Amortization		(42.0)
Taxes Other Than Income Taxes		(0.9)
Other Income		(7.5)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.8)
Interest Expense		0.2
Total Change in Expenses and Other		(23.6)
Income Tax Expense		(13.4)
Nine Months Ended September 30, 2020	$	232.8

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

- **Retail Margins** increased $26 million primarily due to the following:
  - A $72 million increase primarily due to the Indiana and Michigan base rate cases and increases in rider revenues. This increase was partially offset in other expense items below.

  This increase was partially offset by:
  - A $37 million decrease in weather-normalized wholesale margins, including the loss of a significant wholesale contract.
  - An $8 million decrease in weather-related usage primarily due to an 11% decrease in heating degree days.
  - A $6 million decrease in weather-normalized retail margins.
- **Transmission Revenues** increased $10 million primarily due to the following:
  - A $6 million increase from the annual transmission formula rate true-up.
  - A $4 million increase from investment in transmission assets. This increase was partially offset in Other Operation and Maintenance expenses below.
- **Other Revenues** decreased $14 million primarily due to a decrease in barging revenues by RTD. This decrease was partially offset in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses decreased $27 million primarily due to the following:
  - An $18 million decrease in nonutility operation expenses primarily due to a decrease in RTD expenses. This decrease was partially offset in Other Revenues above.
  - An $8 million decrease in distribution expenses primarily due to a decrease in vegetation management expenses.
  - A $7 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2020.
  - A $7 million decrease in Cook Plant refueling outage amortization expense primarily due to decreased costs of outages and various maintenance activities.
  - A $4 million decrease in steam generation expense primarily due to 2019 NSR Consent Decree modifications.

  These decreases were partially offset by:
  - A $12 million increase in transmission expenses primarily due to a $21 million increase in recoverable PJM expenses, partially offset by an $11 million decrease from the annual transmission formula rate true-up. This increase was partially offset in Transmission Revenues above.
  - A $5 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses increased $42 million primarily due to a higher depreciable base and an increase in depreciation rates. This increase was partially offset in Retail Margins above.
- **Other Income** decreased $8 million primarily due to a decrease in the AFUDC base and the favorable impact of a FERC settlement agreement recorded in 2019.
- **Income Tax Expense** increased $13 million primarily due to an increase in state income tax expense and a decrease in favorable flow-through tax benefits.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
REVENUES				
Electric Generation, Transmission and Distribution	$ 570.1	$ 589.1	$ 1,648.4	$ 1,703.2
Sales to AEP Affiliates	1.3	2.7	9.1	7.3
Other Revenues – Affiliated	14.1	16.2	42.4	50.4
Other Revenues – Nonaffiliated	1.2	3.1	3.7	7.6
TOTAL REVENUES	586.7	611.1	1,703.6	1,768.5
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	44.4	61.2	146.0	161.2
Purchased Electricity for Resale	37.5	44.8	128.1	163.3
Purchased Electricity from AEP Affiliates	55.9	61.0	135.8	172.1
Other Operation	165.5	172.7	459.7	467.7
Maintenance	51.0	50.9	144.4	163.8
Depreciation and Amortization	104.5	88.1	303.6	261.6
Taxes Other Than Income Taxes	27.4	25.1	79.5	78.6
TOTAL EXPENSES	486.2	503.8	1,397.1	1,468.3
OPERATING INCOME	100.5	107.3	306.5	300.2
Other Income (Expense):				
Other Income	2.2	3.5	7.8	15.3
Non-Service Cost Components of Net Periodic Benefit Cost	4.1	4.5	12.5	13.3
Interest Expense	(26.9)	(28.8)	(85.7)	(85.9)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	79.9	86.5	241.1	242.9
Income Tax Expense (Benefit)	3.2	(2.3)	8.3	(5.1)
NET INCOME	$ 76.7	$ 88.8	$ 232.8	$ 248.0

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Net Income	$ 76.7	$ 88.8	$ 232.8	$ 248.0
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2020 and 2019, Respectively, and $0.3 and $0.3 for the Nine Months Ended September 30, 2020 and 2019, Respectively	0.4	0.4	1.2	1.2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2020 and 2019, Respectively, and $0 and $0 for the Nine Months Ended September 30, 2020 and 2019, Respectively	(0.1)	—	(0.1)	(0.1)
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.4	1.1	1.1
TOTAL COMPREHENSIVE INCOME	$ 77.0	$ 89.2	$ 233.9	$ 249.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2018	$ 56.6	$ 980.9	$ 1,329.1	$ (13.8)	$ 2,352.8
Common Stock Dividends			(20.0)		(20.0)
Net Income			98.9		98.9
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2019	56.6	980.9	1,408.0	(13.4)	2,432.1
Common Stock Dividends			(20.0)		(20.0)
Net Income			60.3		60.3
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2019	56.6	980.9	1,448.3	(13.1)	2,472.7
Common Stock Dividends			(20.0)		(20.0)
Net Income			88.8		88.8
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2019	$ 56.6	$ 980.9	$ 1,517.1	$ (12.7)	$ 2,541.9
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2019	$ 56.6	$ 980.9	$ 1,518.5	$ (11.6)	$ 2,544.4
Common Stock Dividends			(21.3)		(21.3)
ASU 2016-13 Adoption			0.4		0.4
Net Income			92.3		92.3
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2020	56.6	980.9	1,589.9	(11.2)	2,616.2
Common Stock Dividends			(21.2)		(21.2)
Net Income			63.8		63.8
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2020	56.6	980.9	1,632.5	(10.8)	2,659.2
Common Stock Dividends			(21.2)		(21.2)
Net Income			76.7		76.7
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2020	$ 56.6	$ 980.9	$ 1,688.0	$ (10.5)	$ 2,715.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.8	$ 2.0
Advances to Affiliates	13.3	13.2
Accounts Receivable:		
Customers	34.7	53.6
Affiliated Companies	43.5	53.7
Accrued Unbilled Revenues	—	2.5
Miscellaneous	0.9	0.3
Allowance for Uncollectible Accounts	(0.3)	(0.6)
Total Accounts Receivable	78.8	109.5
Fuel	71.3	56.2
Materials and Supplies	171.4	171.3
Risk Management Assets	4.1	9.8
Accrued Tax Benefits	29.8	—
Regulatory Asset for Under-Recovered Fuel Costs	4.2	3.0
Accrued Reimbursement of Spent Nuclear Fuel Costs	14.7	24.0
Prepayments and Other Current Assets	17.0	14.0
TOTAL CURRENT ASSETS	407.4	403.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,239.8	5,099.7
Transmission	1,665.8	1,641.8
Distribution	2,549.5	2,437.6
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	665.8	632.6
Construction Work in Progress	383.3	382.3
Total Property, Plant and Equipment	10,504.2	10,194.0
Accumulated Depreciation, Depletion and Amortization	3,502.4	3,294.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,001.8	6,899.7
OTHER NONCURRENT ASSETS		
Regulatory Assets	450.2	482.1
Spent Nuclear Fuel and Decommissioning Trusts	3,075.9	2,975.7
Long-term Risk Management Assets	—	0.1
Operating Lease Assets	228.8	294.9
Deferred Charges and Other Noncurrent Assets	160.7	181.9
TOTAL OTHER NONCURRENT ASSETS	3,915.6	3,934.7
TOTAL ASSETS	$ 11,324.8	$ 11,237.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2020 and December 31, 2019
(dollars in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT LIABILITIES		
Advances from Affiliates	$ 159.1	$ 114.4
Accounts Payable:		
General	133.3	169.4
Affiliated Companies	79.7	68.4
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2020 and December 31, 2019 Amounts Include $54.9 and $86.1, Respectively, Related to DCC Fuel)	348.7	139.7
Risk Management Liabilities	0.2	0.5
Customer Deposits	40.2	39.4
Accrued Taxes	57.8	112.4
Accrued Interest	19.9	36.2
Obligations Under Operating Leases	83.8	87.3
Regulatory Liability for Over-Recovered Fuel Costs	30.6	6.1
Other Current Liabilities	91.0	109.6
TOTAL CURRENT LIABILITIES	1,044.3	883.4
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,633.2	2,910.5
Long-term Risk Management Liabilities	0.1	—
Deferred Income Taxes	1,024.0	979.7
Regulatory Liabilities and Deferred Investment Tax Credits	1,879.6	1,891.4
Asset Retirement Obligations	1,796.1	1,748.6
Obligations Under Operating Leases	165.4	211.6
Deferred Credits and Other Noncurrent Liabilities	67.1	67.8
TOTAL NONCURRENT LIABILITIES	7,565.5	7,809.6
TOTAL LIABILITIES	8,609.8	8,693.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	980.9	980.9
Retained Earnings	1,688.0	1,518.5
Accumulated Other Comprehensive Income (Loss)	(10.5)	(11.6)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,715.0	2,544.4
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 11,324.8	$ 11,237.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
OPERATING ACTIVITIES		
Net Income	$ 232.8	$ 248.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	303.6	261.6
Rockport Plant, Unit 2 Operating Lease Amortization	51.9	58.9
Deferred Income Taxes	(6.1)	(29.9)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	21.3	(11.6)
Allowance for Equity Funds Used During Construction	(8.8)	(16.4)
Mark-to-Market of Risk Management Contracts	5.6	(1.6)
Amortization of Nuclear Fuel	67.2	71.6
Pension Contributions to Qualified Plan Trust	(6.4)	—
Deferred Fuel Over/Under-Recovery, Net	23.4	(20.0)
Change in Other Noncurrent Assets	40.8	46.0
Change in Other Noncurrent Liabilities	30.2	13.8
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	32.2	50.5
Fuel, Materials and Supplies	(15.4)	(4.6)
Accounts Payable	(0.9)	(7.3)
Accrued Taxes, Net	(84.4)	(49.4)
Rockport Plant, Unit 2 Operating Lease Payments	(36.9)	(36.9)
Other Current Assets	6.6	7.8
Other Current Liabilities	(59.1)	(49.7)
Net Cash Flows from Operating Activities	597.6	530.8
INVESTING ACTIVITIES		
Construction Expenditures	(409.1)	(431.7)
Change in Advances to Affiliates, Net	(0.1)	(0.5)
Purchases of Investment Securities	(1,290.0)	(915.7)
Sales of Investment Securities	1,257.1	871.4
Acquisitions of Nuclear Fuel	(68.4)	(91.9)
Other Investing Activities	8.3	10.5
Net Cash Flows Used for Investing Activities	(502.2)	(557.9)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	62.9
Change in Advances from Affiliates, Net	44.7	101.3
Retirement of Long-term Debt – Nonaffiliated	(71.1)	(73.6)
Principal Payments for Finance Lease Obligations	(4.8)	(4.0)
Dividends Paid on Common Stock	(63.7)	(60.0)
Other Financing Activities	0.3	0.6
Net Cash Flows from (Used for) Financing Activities	(94.6)	27.2
Net Increase in Cash and Cash Equivalents	0.8	0.1
Cash and Cash Equivalents at Beginning of Period	2.0	2.4
Cash and Cash Equivalents at End of Period	$ 2.8	$ 2.5
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 97.5	$ 98.7
Net Cash Paid for Income Taxes	59.7	40.2
Noncash Acquisitions Under Finance Leases	1.9	8.1
Construction Expenditures Included in Current Liabilities as of September 30,	57.6	76.3
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	1.0	—
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	2.4	—

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

OHIO POWER COMPANY AND SUBSIDIARIES

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
	(in millions of KWhs)			
Retail:				
Residential	4,165	4,120	11,140	11,034
Commercial	3,781	4,067	10,454	11,072
Industrial	3,380	3,689	9,855	10,936
Miscellaneous	22	26	82	83
Total Retail (a)	11,348	11,902	31,531	33,125
Wholesale (b)	502	453	1,347	1,531
Total KWhs	11,850	12,355	32,878	34,656

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

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
	(in degree days)			
Actual – Heating (a)	2	—	1,767	2,006
Normal – Heating (b)	6	6	2,086	2,072
Actual – Cooling (c)	809	872	1,126	1,176
Normal – Cooling (b)	682	672	986	973

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

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Net Income
(in millions)

Third Quarter of 2019	$	69.1
Changes in Gross Margin:		
Retail Margins		56.3
Margins from Off-system Sales		0.5
Transmission Revenues		4.4
Other Revenues		3.5
Total Change in Gross Margin		64.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(43.4)
Depreciation and Amortization		(16.7)
Taxes Other Than Income Taxes		(5.8)
Interest Income		(0.4)
Allowance for Equity Funds Used During Construction		(0.2)
Non-Service Cost Components of Net Periodic Benefit Cost		0.1
Interest Expense		(1.5)
Total Change in Expenses and Other		(67.9)
Income Tax Expense		(6.9)
Third Quarter of 2020	$	59.0

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

- **Retail Margins** increased $56 million primarily due to the following:
  - A $52 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - An $18 million increase in rider revenues associated with the DIR. This increase was partially offset in other expense items below.
  - A $5 million increase in revenues associated with the Universal Service Fund (USF).This increase was offset in Other Operation and Maintenance expenses below.
  - A $3 million increase in revenues associated with smart grid riders. This increase was partially offset in other expense items below.

  These increases were partially offset by:
  - A $10 million decrease in usage primarily in the commercial and residential classes.
  - A $6 million decrease due to the OVEC PPA rider which was replaced by the Legacy Generation Resource Rider (LGRR).This decrease was offset in Margins from Off-system Sales and Other Revenues below.
  - A $3 million decrease in revenues associated with a vegetation management rider. This decrease was partially offset in Other Operation and Maintenance expenses below.
- **Transmission Revenues** increased $4 million primarily due to increased investment in transmission assets.
- **Other Revenues** increased $4 million primarily due to third-party LGRR revenue related to the recovery of OVEC costs.This increase was offset in Retail Margins above.

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

- **Other Operation and Maintenance** expenses increased $43 million primarily due to the following:
  - A $43 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses. This increase was offset in Gross Margin above.
  - A $5 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.

  These increases were partially offset by:
  - A $5 million decrease in recoverable distribution expenses related to vegetation management. This decrease was offset in Retail Margins above.
- **Depreciation and Amortization** expenses increased $17 million primarily due to the following:
  - A $9 million increase in recoverable DIR depreciation expense. This increase was partially offset in Retail Margins above.
  - A $5 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Income Tax Expense** increased $7 million primarily due to the recognition of a discrete tax adjustment which was primarily attributable to the filing of the 2019 Federal Income Tax return in the third quarter of 2020.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Net Income
(in millions)

Nine Months Ended September 30, 2019	$	247.7
Changes in Gross Margin:		
Retail Margins		6.0
Margins from Off-system Sales		7.3
Transmission Revenues		22.8
Other Revenues		12.2
Total Change in Gross Margin		48.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(28.3)
Depreciation and Amortization		(27.6)
Taxes Other Than Income Taxes		(10.9)
Interest Income		(1.9)
Carrying Costs Income		0.6
Allowance for Equity Funds Used During Construction		(4.8)
Non-Service Cost Components of Net Periodic Benefit Cost		0.3
Interest Expense		(10.3)
Total Change in Expenses and Other		(82.9)
Income Tax Expense		1.9
Nine Months Ended September 30, 2020	$	215.0

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

- **Retail Margins** increased $6 million primarily due to the following:
  - A $74 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $48 million increase in rider revenues associated with the DIR. This increase was partially offset in other expense items below.
  - A $15 million increase in revenues associated with smart grid riders. This increase was partially offset in other expense items below.
  - A $15 million increase in revenues associated with the USF. This increase was offset in Other Operation and Maintenance expenses below.

  These increases were partially offset by:
  - A $58 million decrease due to a reversal of a regulatory provision in the first quarter of 2019.
  - A $23 million decrease in Deferred Asset Phase-In-Recovery Rider revenues which ended in the second quarter of 2019. This decrease was partially offset in Depreciation and Amortization expenses below.
  - A $21 million decrease due to the OVEC PPA rider which was replaced by the LGRR.This decrease was offset in Margins from Off-system Sales and Other Revenues below.
  - A $17 million net decrease in margin for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $12 million decrease in usage primarily in the commercial class.
  - A $9 million decrease in revenues associated with a vegetation management rider. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - A $5 million decrease due to a PUCO order to refund unused 2018 major storm reserve collections to customers.This decrease was offset in Other Operation and Maintenance expenses below.

- **Margins from Off-system Sales** increased $7 million primarily due to:
  - An $18 million increase due to higher OVEC PPA deferrals. This increase was offset in Retail Margins above.

  This increase was partially offset by:
  - A $12 million decrease in sales due to lower market prices and decreased sales volumes in 2020. This decrease was offset in Retail Margins above.
- **Transmission Revenues** increased $23 million primarily due to the following:
  - A $16 million increase from the annual transmission formula rate true-up.
  - A $6 million increase due to additional investment in transmission assets.
- **Other Revenues** increased $12 million primarily due to third-party LGRR revenue related to the recovery of OVEC costs.This increase was offset in Retail Margins above.

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

- **Other Operation and Maintenance** expenses increased $28 million primarily due to the following:
  - A $29 million increase in transmission expenses primarily due to a $57 million increase in recoverable PJM expenses partially offset by a $28 million decrease related to the annual transmission formula rate true-up. This increase was offset in Gross Margin above.
  - A $15 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.

  These increases were partially offset by:
  - A $6 million decrease in recoverable distribution expenses related to vegetation management. This decrease was offset in Retail Margins above.
  - A $5 million decrease due to a PUCO order to refund unused 2018 major storm reserve collections to customers.This decrease was offset in Retail Margins above.
- **Depreciation and Amortization** expenses increased $28 million primarily due to the following:
  - A $16 million increase in recoverable DIR depreciation expense. This increase was partially offset in Retail Margins above.
  - A $14 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.
  - A $6 million increase in recoverable smart grid expense. This increase was offset in Retail Margins above.

  These increases were partially offset by:
  - A $24 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $11 million primarily due to the following:
  - A $16 million increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.

  This increase was partially offset by:
  - A $4 million decrease in excise taxes due to lower demand in 2020. This decrease was offset in Retail Margins above.
- **Allowance for Equity Funds Used During Construction**decreased $5 million primarily due to adjustments that resulted from 2019 FERC audit findings and a decrease in AFUDC base.
- **Interest Expense** increased $10 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $2 million due to a decrease in pretax book income, partially offset by the recognition of a discrete tax adjustment.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
REVENUES				
Electricity, Transmission and Distribution	$ 730.4	$ 698.6	$ 2,031.4	$ 2,127.4
Sales to AEP Affiliates	8.3	9.0	33.0	18.2
Other Revenues	2.3	3.0	7.3	8.4
TOTAL REVENUES	741.0	710.6	2,071.7	2,154.0
EXPENSES				
Purchased Electricity for Resale	149.3	158.3	412.3	454.0
Purchased Electricity from AEP Affiliates	24.1	40.6	96.8	120.4
Amortization of Generation Deferrals	—	8.8	—	65.3
Other Operation	244.6	194.9	608.5	565.7
Maintenance	33.7	40.0	92.2	106.7
Depreciation and Amortization	74.1	57.4	204.4	176.8
Taxes Other Than Income Taxes	117.8	112.0	337.8	326.9
TOTAL EXPENSES	643.6	612.0	1,752.0	1,815.8
OPERATING INCOME	97.4	98.6	319.7	338.2
Other Income (Expense):				
Interest Income	0.4	0.8	0.8	2.7
Carrying Costs Income	0.3	0.3	1.3	0.7
Allowance for Equity Funds Used During Construction	4.6	4.8	9.3	14.1
Non-Service Cost Components of Net Periodic Benefit Cost	3.8	3.7	11.3	11.0
Interest Expense	(29.4)	(27.9)	(88.4)	(78.1)
INCOME BEFORE INCOME TAX EXPENSE	77.1	80.3	254.0	288.6
Income Tax Expense	18.1	11.2	39.0	40.9
NET INCOME	$ 59.0	$ 69.1	$ 215.0	$ 247.7

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
Net Income	$ 59.0	$ 69.1	$ 215.0	$ 247.7
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $(0.1) for the Three Months Ended September 30, 2020 and 2019, Respectively, and $0 and $(0.3) for the Nine Months Ended September 30, 2020 and 2019, Respectively	—	(0.3)	—	(1.0)
TOTAL COMPREHENSIVE INCOME	$ 59.0	$ 68.8	$ 215.0	$ 246.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 321.2	$ 838.8	$ 1,136.4	$ 1.0	$ 2,297.4
Common Stock Dividends			(25.0)		(25.0)
Net Income			128.0		128.0
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	321.2	838.8	1,239.4	0.7	2,400.1
Common Stock Dividends			(60.0)		(60.0)
Net Income			50.6		50.6
Other Comprehensive Loss				(0.4)	(0.4)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	321.2	838.8	1,230.0	0.3	2,390.3
Net Income			69.1		69.1
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2019	$ 321.2	$ 838.8	$ 1,299.1	$ —	$ 2,459.1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 321.2	$ 838.8	$ 1,348.5	$ —	$ 2,508.5
Common Stock Dividends			(21.9)		(21.9)
ASU 2016-13 Adoption			0.3		0.3
Net Income			75.1		75.1
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2020	321.2	838.8	1,402.0	—	2,562.0
Common Stock Dividends			(21.9)		(21.9)
Net Income			80.9		80.9
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2020	321.2	838.8	1,461.0	—	2,621.0
Common Stock Dividends			(21.8)		(21.8)
Net Income			59.0		59.0
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2020	$ 321.2	$ 838.8	$ 1,498.2	$ —	$ 2,658.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

		September 30, 2020		December 31, 2019
CURRENT ASSETS				
Cash and Cash Equivalents	$	6.6	$	3.7
Accounts Receivable:				
Customers		18.4		53.0
Affiliated Companies		61.0		59.3
Accrued Unbilled Revenues		20.1		20.3
Miscellaneous		3.9		0.5
Allowance for Uncollectible Accounts		(0.7)		(0.7)
Total Accounts Receivable		102.7		132.4
Materials and Supplies		67.0		52.3
Renewable Energy Credits		28.7		30.9
Accrued Tax Benefits		4.3		11.5
Prepayments and Other Current Assets		13.2		7.7
TOTAL CURRENT ASSETS		222.5		238.5
PROPERTY, PLANT AND EQUIPMENT				
Electric:				
Transmission		2,768.1		2,686.3
Distribution		5,545.8		5,323.5
Other Property, Plant and Equipment		882.4		765.8
Construction Work in Progress		455.9		394.4
Total Property, Plant and Equipment		9,652.2		9,170.0
Accumulated Depreciation and Amortization		2,350.1		2,263.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET		7,302.1		6,907.0
OTHER NONCURRENT ASSETS				
Regulatory Assets		401.7		351.8
Deferred Charges and Other Noncurrent Assets		340.6		546.3
TOTAL OTHER NONCURRENT ASSETS		742.3		898.1
TOTAL ASSETS	$	8,266.9	$	8,043.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2020 and December 31, 2019
(dollars in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT LIABILITIES		
Advances from Affiliates	$ 215.9	$ 131.0
Accounts Payable:		
General	184.5	233.7
Affiliated Companies	90.7	103.6
Long-term Debt Due Within One Year – Nonaffiliated	0.1	0.1
Risk Management Liabilities	8.2	7.3
Customer Deposits	58.2	70.6
Accrued Taxes	314.5	587.9
Obligations Under Operating Leases	12.5	12.5
Other Current Liabilities	141.1	151.2
TOTAL CURRENT LIABILITIES	1,025.7	1,297.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,429.8	2,081.9
Long-term Risk Management Liabilities	105.1	96.3
Deferred Income Taxes	904.6	849.4
Regulatory Liabilities and Deferred Investment Tax Credits	1,018.5	1,090.9
Obligations Under Operating Leases	76.7	76.0
Deferred Credits and Other Noncurrent Liabilities	48.3	42.7
TOTAL NONCURRENT LIABILITIES	4,583.0	4,237.2
TOTAL LIABILITIES	5,608.7	5,535.1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	1,498.2	1,348.5
TOTAL COMMON SHAREHOLDER'S EQUITY	2,658.2	2,508.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 8,266.9	$ 8,043.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
OPERATING ACTIVITIES		
Net Income	$ 215.0	$ 247.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	204.4	176.8
Amortization of Generation Deferrals	—	65.3
Deferred Income Taxes	35.6	16.8
Allowance for Equity Funds Used During Construction	(9.3)	(14.1)
Mark-to-Market of Risk Management Contracts	9.7	13.3
Property Taxes	225.1	197.7
Refund of Global Settlement	—	(12.4)
Reversal of Regulatory Provision	—	(56.2)
Change in Other Noncurrent Assets	(93.8)	(47.5)
Change in Other Noncurrent Liabilities	(58.3)	(51.1)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	33.4	90.0
Materials and Supplies	(19.8)	(9.6)
Accounts Payable	(19.9)	(12.3)
Accrued Taxes, Net	(266.2)	(245.9)
Other Current Assets	(2.5)	(9.0)
Other Current Liabilities	(23.3)	(40.0)
Net Cash Flows from Operating Activities	230.1	309.5
INVESTING ACTIVITIES		
Construction Expenditures	(604.6)	(570.6)
Other Investing Activities	14.1	20.0
Net Cash Flows Used for Investing Activities	(590.5)	(550.6)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	347.0	444.3
Change in Advances from Affiliates, Net	84.9	(96.5)
Retirement of Long-term Debt – Nonaffiliated	(0.1)	(48.0)
Principal Payments for Finance Lease Obligations	(3.5)	(2.6)
Dividends Paid on Common Stock	(65.6)	(85.0)
Other Financing Activities	0.6	1.1
Net Cash Flows from Financing Activities	363.3	213.3
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	2.9	(27.8)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	3.7	32.5
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 6.6	$ 4.7
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 69.7	$ 61.3
Net Cash Paid (Received) for Income Taxes	(6.0)	25.7
Noncash Acquisitions Under Finance Leases	5.2	8.6
Construction Expenditures Included in Current Liabilities as of September 30,	75.9	99.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

PUBLIC SERVICE COMPANY OF OKLAHOMA

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions of KWhs)			
Retail:				
Residential	2,019	2,172	4,838	4,981
Commercial	1,358	1,497	3,549	3,818
Industrial	1,461	1,642	4,299	4,665
Miscellaneous	347	378	912	950
Total Retail	5,185	5,689	13,598	14,414
Wholesale	130	224	261	617
Total KWhs	5,315	5,913	13,859	15,031

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in degree days)			
Actual – Heating (a)	1	—	874	1,199
Normal – Heating (b)	1	1	1,078	1,077
Actual – Cooling (c)	1,274	1,593	1,979	2,206
Normal – Cooling (b)	1,412	1,397	2,088	2,072

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

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Net Income
(in millions)

Third Quarter of 2019	$	100.3
Changes in Gross Margin:		
Retail Margins (a)		(20.7)
Margins from Off-system Sales		(1.3)
Transmission Revenues		(0.5)
Other Revenues		(0.2)
Total Change in Gross Margin		(22.7)
Changes in Expenses and Other:		
Other Operation and Maintenance		(2.5)
Depreciation and Amortization		(1.0)
Taxes Other Than Income Taxes		(1.0)
Interest Income		(0.4)
Allowance for Equity Funds Used During Construction		0.5
Interest Expense		1.5
Total Change in Expenses and Other		(2.9)
Income Tax Expense		5.6
Third Quarter of 2020	$	80.3

(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 $21 million primarily due to the following:
  - An $18 million decrease in weather-related usage due to a 20% decrease in cooling degree-days.
  - A $4 million decrease in revenue from rate riders. This decrease was partially offset in other expense items below.

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

- **Other Operation and Maintenance** expenses increased $3 million primarily due to the following:
  - A $4 million increase in transmission expenses due to an increase in recoverable SPP expenses. This increase was partially offset in Retail Margins above.
  - A $2 million increase in customer-related expenses primarily related to energy efficiency programs. This increase was partially offset in Retail Margins above.

  These increases were partially offset by:
  - A $4 million decrease in distribution expenses.
- **Income Tax Expense** decreased $6 million primarily due to a decrease in pretax book income.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Net Income
(in millions)

Nine Months Ended September 30, 2019	$	148.4
Changes in Gross Margin:		
Retail Margins (a)		(15.1)
Margin from Off-system Sales		(1.7)
Transmission Revenues		(0.8)
Other Revenues		3.4
Total Change in Gross Margin		(14.2)
Changes in Expenses and Other:		
Other Operation and Maintenance		(21.3)
Depreciation and Amortization		(4.4)
Taxes Other Than Income Taxes		(2.8)
Interest Income		(0.5)
Allowance for Equity Funds Used During Construction		1.7
Interest Expense		4.4
Total Change in Expenses and Other		(22.9)
Income Tax Expense		5.1
Nine Months Ended September 30, 2020	$	116.4

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

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

- **Retail Margins** decreased $15 million primarily due to the following:
  - A $15 million decrease in weather-related usage due to a 10% decrease in cooling degree-days.
  - A $10 million decrease in revenue from rate riders. This decrease was partially offset in other expense items below.
  - A $7 million decrease due to customer refunds related to Tax Reform. This decrease is partially offset in Income Tax Expense below.

  These decreases were partially offset by:
  - A $10 million increase due to new base rates implemented in April 2019.
  - A $7 million increase in weather-normalized margins.
- **Other Revenues** increased $3 million primarily due to business development revenue. This increase was offset in other expense items below.

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

- **Other Operation and Maintenance** expenses increased $21 million primarily due to the following:
  - A $20 million increase in transmission expenses primarily due to the annual transmission formula rate true-up. This increase was partially offset in Retail Margins above.
  - A $5 million increase in customer-related expenses primarily related to energy efficiency programs. This increase was partially offset in Retail Margins above.
  - A $4 million increase in business development expenses. This increase was partially offset in Other Revenues above.
  - A $4 million increase in maintenance of overhead lines for non-storm related expenses.

  These increases were partially offset by:
  - A $7 million decrease in expenses at various generation plants.
  - A $5 million decrease due to the capitalization of previously expensed North Central Wind Energy Facilities costs.

- **Depreciation and Amortization** expenses increased $4 million primarily due to a higher depreciable base.
- **Interest Expense** decreased $4 million primarily due to lower interest rates on long-term debt.
- **Income Tax Expense** decreased $5 million primarily due to a decrease in pretax book income, partially offset by a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT is partially offset in Retail Margins above.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
REVENUES				
Electric Generation, Transmission and Distribution	$ 379.8	$ 490.5	$ 976.3	$ 1,164.3
Sales to AEP Affiliates	1.4	1.3	3.8	5.0
Other Revenues	1.0	1.2	8.0	4.6
TOTAL REVENUES	382.2	493.0	988.1	1,173.9
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	20.9	98.4	36.2	181.2
Purchased Electricity for Resale	104.7	115.3	314.1	340.7
Other Operation	91.7	87.6	248.5	226.0
Maintenance	19.9	21.5	68.9	70.1
Depreciation and Amortization	40.1	39.1	129.8	125.4
Taxes Other Than Income Taxes	12.1	11.1	35.8	33.0
TOTAL EXPENSES	289.4	373.0	833.3	976.4
OPERATING INCOME	92.8	120.0	154.8	197.5
Other Income (Expense):				
Interest Income	—	0.4	0.1	0.6
Allowance for Equity Funds Used During Construction	1.3	0.8	3.2	1.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	2.1	6.3	6.3
Interest Expense	(14.6)	(16.1)	(45.9)	(50.3)
INCOME BEFORE INCOME TAX EXPENSE	81.6	107.2	118.5	155.6
Income Tax Expense	1.3	6.9	2.1	7.2
NET INCOME	$ 80.3	$ 100.3	$ 116.4	$ 148.4

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
Net Income	$ 80.3	$ 100.3	$ 116.4	$ 148.4
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2020 and 2019, Respectively, and $(0.2) and $(0.2) for the Nine Months Ended September 30, 2020 and 2019, Respectively.	(0.3)	(0.2)	(0.8)	(0.7)
TOTAL COMPREHENSIVE INCOME	$ 80.0	$ 100.1	$ 115.6	$ 147.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 157.2	$ 364.0	$ 724.7	$ 2.1	$ 1,248.0
Common Stock Dividends			(11.3)		(11.3)
Net Income			6.2		6.2
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2019	157.2	364.0	719.6	1.9	1,242.7
Net Income			41.9		41.9
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2019	157.2	364.0	761.5	1.6	1,284.3
Net Income			100.3		100.3
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2019	$ 157.2	$ 364.0	$ 861.8	$ 1.4	$ 1,384.4
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 157.2	$ 364.0	$ 851.0	$ 1.1	$ 1,373.3
ASU 2016-13 Adoption			0.3		0.3
Net Loss			(10.3)		(10.3)
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2020	157.2	364.0	841.0	0.9	1,363.1
Net Income			46.4		46.4
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2020	157.2	364.0	887.4	0.6	1,409.2
Net Income			80.3		80.3
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2020	$ 157.2	$ 364.0	$ 967.7	$ 0.3	$ 1,489.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.0	$ 1.5
Advances to Affiliates	—	38.8
Accounts Receivable:		
Customers	25.2	28.9
Affiliated Companies	27.1	20.6
Miscellaneous	3.1	0.6
Allowance for Uncollectible Accounts	—	(0.3)
Total Accounts Receivable	55.4	49.8
Fuel	22.8	12.2
Materials and Supplies	53.4	46.8
Risk Management Assets	16.6	15.8
Accrued Tax Benefits	0.6	11.3
Prepayments and Other Current Assets	11.8	12.0
TOTAL CURRENT ASSETS	163.6	188.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,474.1	1,574.6
Transmission	981.2	948.5
Distribution	2,799.5	2,684.8
Other Property, Plant and Equipment	381.8	342.1
Construction Work in Progress	147.2	133.4
Total Property, Plant and Equipment	5,783.8	5,683.4
Accumulated Depreciation and Amortization	1,578.3	1,580.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	4,205.5	4,103.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	388.9	375.2
Employee Benefits and Pension Assets	44.8	43.9
Operating Lease Assets	40.5	36.8
Deferred Charges and Other Noncurrent Assets	15.9	4.1
TOTAL OTHER NONCURRENT ASSETS	490.1	460.0
TOTAL ASSETS	$ 4,859.2	$ 4,751.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2020 and December 31, 2019
(Unaudited)

	September 30, 2020	December 31, 2019
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 77.8	$ —
Accounts Payable:		
General	106.7	134.3
Affiliated Companies	41.0	59.3
Long-term Debt Due Within One Year – Nonaffiliated	250.5	13.2
Risk Management Liabilities	0.5	—
Customer Deposits	56.2	58.9
Accrued Taxes	49.1	22.9
Obligations Under Operating Leases	6.2	5.8
Regulatory Liability for Over-Recovered Fuel Costs	17.3	63.9
Other Current Liabilities	72.8	87.5
TOTAL CURRENT LIABILITIES	678.1	445.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,123.2	1,373.0
Deferred Income Taxes	649.6	628.3
Regulatory Liabilities and Deferred Investment Tax Credits	816.4	837.2
Asset Retirement Obligations	46.4	44.5
Obligations Under Operating Leases	34.3	31.0
Deferred Credits and Other Noncurrent Liabilities	22.0	18.4
TOTAL NONCURRENT LIABILITIES	2,691.9	2,932.4
TOTAL LIABILITIES	3,370.0	3,378.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157.2	157.2
Paid-in Capital	364.0	364.0
Retained Earnings	967.7	851.0
Accumulated Other Comprehensive Income (Loss)	0.3	1.1
TOTAL COMMON SHAREHOLDER'S EQUITY	1,489.2	1,373.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 4,859.2	$ 4,751.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2020	2019
OPERATING ACTIVITIES		
Net Income	$ 116.4	$ 148.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	129.8	125.4
Deferred Income Taxes	(3.2)	(9.7)
Allowance for Equity Funds Used During Construction	(3.2)	(1.5)
Mark-to-Market of Risk Management Contracts	(0.3)	(12.0)
Property Taxes	(10.6)	(9.6)
Deferred Fuel Over/Under-Recovery, Net	(46.6)	49.8
Change in Other Noncurrent Assets	(7.2)	4.6
Change in Other Noncurrent Liabilities	6.1	(0.2)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(5.6)	9.1
Fuel, Materials and Supplies	(17.2)	(1.9)
Accounts Payable	(26.1)	(5.8)
Accrued Taxes, Net	36.9	19.0
Other Current Assets	(0.1)	(2.4)
Other Current Liabilities	(16.4)	1.1
Net Cash Flows from Operating Activities	152.7	314.3
INVESTING ACTIVITIES		
Construction Expenditures	(256.4)	(198.7)
Change in Advances to Affiliates, Net	38.8	(95.1)
Other Investing Activities	3.9	2.1
Net Cash Flows Used for Investing Activities	(213.7)	(291.7)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	—	349.8
Change in Advances from Affiliates, Net	77.8	(105.5)
Retirement of Long-term Debt – Nonaffiliated	(13.0)	(250.4)
Principal Payments for Finance Lease Obligations	(2.7)	(2.2)
Dividends Paid on Common Stock	—	(11.3)
Other Financing Activities	0.4	(2.1)
Net Cash Flows from (Used for) Financing Activities	62.5	(21.7)
Net Increase in Cash and Cash Equivalents	1.5	0.9
Cash and Cash Equivalents at Beginning of Period	1.5	2.0
Cash and Cash Equivalents at End of Period	$ 3.0	$ 2.9
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 45.5	$ 46.5
Net Cash Paid (Received) for Income Taxes	(9.5)	16.0
Noncash Acquisitions Under Finance Leases	3.0	3.4
Construction Expenditures Included in Current Liabilities as of September 30,	23.5	31.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
		(in millions of KWhs)		
Retail:				
Residential	1,950	2,071	4,702	4,896
Commercial	1,552	1,746	4,016	4,430
Industrial	1,185	1,414	3,614	4,020
Miscellaneous	19	19	59	59
Total Retail	4,706	5,250	12,391	13,405
Wholesale	1,571	1,831	4,081	5,317
Total KWhs	6,277	7,081	16,472	18,722

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	**2019**	**2020**	**2019**
		(in degree days)		
Actual – Heating (a)	—	—	522	732
Normal – Heating (b)	1	1	724	725
Actual – Cooling (c)	1,308	1,552	2,051	2,263
Normal – Cooling (b)	1,420	1,408	2,200	2,187

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

Third Quarter of 2020 Compared to Third Quarter of 2019

Reconciliation of Third Quarter of 2019 to Third Quarter of 2020
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2019	$	110.5
Changes in Gross Margin:		
Retail Margins (a)		(8.9)
Margins from Off-system Sales		(0.3)
Transmission Revenues		2.5
Other Revenues		(0.6)
Total Change in Gross Margin		(7.3)
Changes in Expenses and Other:		
Other Operation and Maintenance		0.3
Depreciation and Amortization		(5.3)
Taxes Other Than Income Taxes		(0.5)
Allowance for Equity Funds Used During Construction		1.8
Interest Expense		(0.1)
Total Change in Expenses and Other		(3.8)
Income Tax Expense		(11.5)
Equity Earnings of Unconsolidated Subsidiary		(0.1)
Net Income Attributable to Noncontrolling Interest		0.1
Third Quarter of 2020	$	87.9

(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 $9 million primarily due to the following:
  - A $17 million decrease in weather-related usage primarily due to a 16% decrease in cooling degree days.
  - An $8 million decrease in weather-normalized margins.

  These decreases were partially offset by:
  - A $14 million increase primarily due to a base rate revenue increase in Arkansas.

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

- **Depreciation and Amortization** expenses increased $5 million primarily due to a higher depreciable base and an increase in Arkansas depreciation rates beginning in January 2020. This increase was partially offset in Retail Margins above.
- **Income Tax Expense** increased $12 million primarily due to a decrease in amortization of Excess ADIT, partially offset by a decrease in pretax book income. The decrease in amortization of Excess ADIT was partially offset in Retail Margins above.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019

Reconciliation of Nine Months Ended September 30, 2019 to Nine Months Ended September 30, 2020
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2019	$	144.5
Changes in Gross Margin:		
Retail Margins (a)		4.4
Margins from Off-system Sales		(2.5)
Transmission Revenues		55.8
Other Revenues		(2.4)
Total Change in Gross Margin		55.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(9.7)
Depreciation and Amortization		(16.8)
Taxes Other Than Income Taxes		(1.0)
Interest Income		(0.3)
Allowance for Equity Funds Used During Construction		1.2
Non-Service Cost Components of Net Periodic Benefit Cost		(0.1)
Interest Expense		0.3
Total Change in Expenses and Other		(26.4)
Income Tax Expense		(12.5)
Equity Earnings of Unconsolidated Subsidiary		(0.1)
Net Income Attributable to Noncontrolling Interest		1.0
Nine Months Ended September 30, 2020	$	161.8

(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 $4 million primarily due to the following:
  - A $35 million increase primarily due to rider increases in all jurisdictions and a base rate revenue increase in Arkansas. This increase was partially offset in other expense items below.
  - A $6 million increase in municipal and cooperative revenues primarily due to formula rate true-ups.
  - A $4 million increase in recoverable fuel costs primarily due to timing of recovery.

  These increases were partially offset by:
  - A $23 million decrease in weather-related usage primarily due to a 9% decrease in cooling degree days and a 29% decrease in heating degree days.
  - A $17 million decrease in weather-normalized margins.
- **Transmission Revenues** increased $56 million primarily due to the following:
  - A $36 million increase as a result of the annual transmission formula rate true-up. This increase was partially offset by an increase in transmission expenses in SPP.
  - A $14 million increase due to continued investment in transmission projects.

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

- **Other Operation and Maintenance** expenses increased $10 million primarily due to the following:
  - A $20 million increase in SPP transmission expenses primarily due to the annual transmission formula rate true-up. This increase was offset in Transmission Revenues above.
  - A $9 million increase in administrative and general expenses and employee-related expenses.

  These increases were partially offset by:
  - An $8 million decrease due to the capitalization of previously expensed North Central Wind Energy Facilities costs.
  - A $6 million decrease in generation plant maintenance expenses.
  - A $4 million decrease in customer-related expenses primarily in energy efficiency programs. This decrease is offset in Retail Margins above.
- **Depreciation and Amortization** expenses increased $17 million primarily due to a higher depreciable base and an increase in Arkansas depreciation rates beginning in January 2020. This increase was partially offset in Retail Margins above.
- **Income Tax Expense** increased $13 million primarily due to a decrease in amortization of Excess ADIT and an increase in pretax book income. The decrease in amortization of Excess ADIT is partially offset in Retail Margins above.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
REVENUES				
Electric Generation, Transmission and Distribution	$ 505.7	$ 536.5	$ 1,284.3	$ 1,344.8
Sales to AEP Affiliates	8.5	8.8	33.5	21.6
Provision for Refund – Affiliated	2.4	(0.1)	(2.0)	(25.3)
Other Revenues	0.7	0.3	2.4	1.0
TOTAL REVENUES	517.3	545.5	1,318.2	1,342.1
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	131.7	148.8	306.4	400.2
Purchased Electricity for Resale	41.0	44.8	125.1	110.5
Other Operation	96.8	91.9	259.0	242.4
Maintenance	30.7	35.9	97.2	104.1
Depreciation and Amortization	68.5	63.2	203.9	187.1
Taxes Other Than Income Taxes	26.7	26.2	77.0	76.0
TOTAL EXPENSES	395.4	410.8	1,068.6	1,120.3
OPERATING INCOME	121.9	134.7	249.6	221.8
Other Income (Expense):				
Interest Income	0.6	0.6	1.7	2.0
Allowance for Equity Funds Used During Construction	3.4	1.6	5.7	4.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	2.1	6.3	6.4
Interest Expense	(29.3)	(29.2)	(89.1)	(89.4)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	98.7	109.8	174.2	145.3
Income Tax Expense (Benefit)	10.8	(0.7)	12.5	—
Equity Earnings of Unconsolidated Subsidiary	0.7	0.8	2.2	2.3
NET INCOME	88.6	111.3	163.9	147.6
Net Income Attributable to Noncontrolling Interest	0.7	0.8	2.1	3.1
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 87.9	$ 110.5	$ 161.8	$ 144.5

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Net Income	$ 88.6	$ 111.3	$ 163.9	$ 147.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2020 and 2019, Respectively, and $0.3 and $0.3 for the Nine Months Ended September 30, 2020 and 2019, Respectively	0.4	0.3	1.1	1.1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $0 for the Three Months Ended September 30, 2020 and 2019, Respectively, and $(0.3) and $(0.2) for the Nine Months Ended September 30, 2020 and 2019, Respectively	(0.4)	(0.3)	(1.1)	(0.9)
TOTAL OTHER COMPREHENSIVE INCOME	—	—	—	0.2
TOTAL COMPREHENSIVE INCOME	88.6	111.3	163.9	147.8
Total Comprehensive Income Attributable to Noncontrolling Interest	0.7	0.8	2.1	3.1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 87.9	$ 110.5	$ 161.8	$ 144.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2018	$ 135.7	$ 676.6	$ 1,508.4	$ (5.4)	$ 0.3	$ 2,315.6
Common Stock Dividends			(18.7)			(18.7)
Common Stock Dividends – Nonaffiliated					(1.1)	(1.1)
Net Income			27.8		1.2	29.0
Other Comprehensive Income				0.1		0.1
TOTAL EQUITY – MARCH 31, 2019	135.7	676.6	1,517.5	(5.3)	0.4	2,324.9
Common Stock Dividends			(18.8)			(18.8)
Common Stock Dividends – Nonaffiliated					(1.1)	(1.1)
Net Income			6.2		1.1	7.3
Other Comprehensive Income				0.1		0.1
TOTAL EQUITY – JUNE 30, 2019	135.7	676.6	1,504.9	(5.2)	0.4	2,312.4
Common Stock Dividends – Nonaffiliated					(1.1)	(1.1)
Net Income			110.5		0.8	111.3
TOTAL EQUITY – SEPTEMBER 30, 2019	$ 135.7	$ 676.6	$ 1,615.4	$ (5.2)	$ 0.1	$ 2,422.6
TOTAL EQUITY – DECEMBER 31, 2019	$ 135.7	$ 676.6	$ 1,629.5	$ (1.3)	$ 0.6	$ 2,441.1
Common Stock Dividends – Nonaffiliated					(0.7)	(0.7)
ASU 2016-13 Adoption			1.6			1.6
Net Income			15.1		1.0	16.1
TOTAL EQUITY – MARCH 31, 2020	135.7	676.6	1,646.2	(1.3)	0.9	2,458.1
Common Stock Dividends – Nonaffiliated					(1.2)	(1.2)
Net Income			58.8		0.4	59.2
TOTAL EQUITY – JUNE 30, 2020	135.7	676.6	1,705.0	(1.3)	0.1	2,516.1
Reverse Common Stock Split (a)	(135.6)	135.6				—
Common Stock Dividends – Nonaffiliated					(0.4)	(0.4)
Net Income			87.9		0.7	88.6
TOTAL EQUITY – SEPTEMBER 30, 2020	$ 0.1	$ 812.2	$ 1,792.9	$ (1.3)	$ 0.4	$ 2,604.3

(a) See Note 12 - Financing Activities for additional information.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2020 and December 31, 2019
(in millions)
(Unaudited)

	September 30, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 25.6	$ 1.6
Advances to Affiliates	2.1	2.1
Accounts Receivable:		
Customers	12.7	29.0
Affiliated Companies	28.3	34.5
Miscellaneous	24.4	13.5
Allowance for Uncollectible Accounts	—	(1.7)
Total Accounts Receivable	65.4	75.3
Fuel (September 30, 2020 and December 31, 2019 Amounts Include $48.7 and $47, Respectively, Related to Sabine)	210.5	140.1
Materials and Supplies (September 30, 2020 and December 31, 2019 Amounts Include $24 and $23.1, Respectively, Related to Sabine)	99.2	94.0
Risk Management Assets	4.5	6.4
Regulatory Asset for Under-Recovered Fuel Costs	7.0	4.9
Prepayments and Other Current Assets	29.7	29.7
TOTAL CURRENT ASSETS	444.0	354.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,674.7	4,691.4
Transmission	2,109.6	2,056.5
Distribution	2,356.6	2,270.7
Other Property, Plant and Equipment (September 30, 2020 and December 31, 2019 Amounts Include $216.8 and $212.3, Respectively, Related to Sabine)	792.5	733.4
Construction Work in Progress	272.3	216.9
Total Property, Plant and Equipment	10,205.7	9,968.9
Accumulated Depreciation and Amortization (September 30, 2020 and December 31, 2019 Amounts Include $117.4 and $107.5, Respectively, Related to Sabine)	3,092.6	2,873.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,113.1	7,095.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	334.8	222.4
Deferred Charges and Other Noncurrent Assets	245.4	160.5
TOTAL OTHER NONCURRENT ASSETS	580.2	382.9
TOTAL ASSETS	$ 8,137.3	$ 7,832.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2020 and December 31, 2019
(Unaudited)

	September 30, 2020	December 31, 2019
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 71.8	$ 59.9
Accounts Payable:		
General	183.3	138.0
Affiliated Companies	80.5	53.6
Short-term Debt – Nonaffiliated	42.0	18.3
Long-term Debt Due Within One Year – Nonaffiliated	6.2	121.2
Risk Management Liabilities	0.1	1.9
Customer Deposits	63.7	65.0
Accrued Taxes	90.1	41.8
Accrued Interest	23.0	34.6
Obligations Under Operating Leases	8.1	6.5
Regulatory Liability for Over-Recovered Fuel Costs	32.0	13.6
Other Current Liabilities	98.7	120.3
TOTAL CURRENT LIABILITIES	699.5	674.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,631.1	2,534.4
Long-term Risk Management Liabilities	0.7	3.1
Deferred Income Taxes	965.0	940.9
Regulatory Liabilities and Deferred Investment Tax Credits	877.5	892.3
Asset Retirement Obligations	202.4	196.7
Obligations Under Operating Leases	43.8	34.7
Deferred Credits and Other Noncurrent Liabilities	113.0	114.3
TOTAL NONCURRENT LIABILITIES	4,833.5	4,716.4
TOTAL LIABILITIES	5,533.0	5,391.1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 3,680 Shares		
Outstanding – 3,680 Shares	0.1	135.7
Paid-in Capital	812.2	676.6
Retained Earnings	1,792.9	1,629.5
Accumulated Other Comprehensive Income (Loss)	(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,603.9	2,440.5
Noncontrolling Interest	0.4	0.6
TOTAL EQUITY	2,604.3	2,441.1
TOTAL LIABILITIES AND EQUITY	$ 8,137.3	$ 7,832.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2020 and 2019
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2020	**2019**
OPERATING ACTIVITIES		
Net Income	$ 163.9	$ 147.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	203.9	187.1
Deferred Income Taxes	(0.3)	(15.9)
Allowance for Equity Funds Used During Construction	(5.7)	(4.5)
Mark-to-Market of Risk Management Contracts	(2.3)	(2.5)
Pension Contributions to Qualified Plan Trust	(8.9)	—
Property Taxes	(16.5)	(16.1)
Deferred Fuel Over/Under-Recovery, Net	16.3	14.1
Change in Regulatory Assets	(64.5)	5.7
Change in Other Noncurrent Assets	3.2	(2.2)
Change in Other Noncurrent Liabilities	21.0	5.8
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	8.0	(17.2)
Fuel, Materials and Supplies	(70.9)	(17.7)
Accounts Payable	88.0	(12.8)
Accrued Taxes, Net	46.6	54.1
Other Current Assets	1.3	(4.5)
Other Current Liabilities	(50.3)	(13.9)
Net Cash Flows from Operating Activities	332.8	307.1
INVESTING ACTIVITIES		
Construction Expenditures	(319.5)	(277.3)
Change in Advances to Affiliates, Net	—	74.9
Other Investing Activities	4.8	(1.2)
Net Cash Flows Used for Investing Activities	(314.7)	(203.6)
FINANCING ACTIVITIES		
Change in Short-term Debt – Nonaffiliated	23.7	—
Change in Advances from Affiliates, Net	11.9	—
Retirement of Long-term Debt – Nonaffiliated	(19.7)	(58.2)
Principal Payments for Finance Lease Obligations	(8.0)	(8.1)
Dividends Paid on Common Stock	—	(37.5)
Dividends Paid on Common Stock – Nonaffiliated	(2.3)	(3.3)
Other Financing Activities	0.3	0.5
Net Cash Flows from (Used for) Financing Activities	5.9	(106.6)
Net Increase (Decrease) in Cash and Cash Equivalents	24.0	(3.1)
Cash and Cash Equivalents at Beginning of Period	1.6	24.5
Cash and Cash Equivalents at End of Period	$ 25.6	$ 21.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 95.2	$ 95.1
Net Cash Paid for Income Taxes	11.9	7.3
Noncash Acquisitions Under Finance Leases	5.9	4.7
Construction Expenditures Included in Current Liabilities as of September 30,	50.6	52.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 134.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

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

1. SIGNIFICANT ACCOUNTING MATTERS

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

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three and nine months ended September 30, 2020 is not necessarily indicative of results that may be expected for the year ending December 31, 2020. The condensed financial statements are unaudited and should be read in conjunction with the audited 2019 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 20, 2020.

COVID-19

In March 2020, COVID-19 was declared a pandemic by the World Health Organization and the Centers for Disease Control and Prevention. Its rapid spread around the world and throughout the United States prompted many countries, including the United States, to institute restrictions on travel, public gatherings and certain business operations. These restrictions significantly disrupted economic activity in AEP's service territory and could reduce future demand for energy, particularly from commercial and industrial customers. The Registrants are taking steps to mitigate the potential risks to customers, suppliers and employees posed by the spread of COVID-19.

As of September 30, 2020 and through the date of this report, the Registrants assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, the allowance for credit losses and the carrying value of long-lived assets. While there were not any impairments or significant increases in credit allowances resulting from these assessments for the three and nine months ended September 30, 2020, the ultimate impact of COVID-19 also depends on factors beyond management's knowledge or control, including the duration and severity of this outbreak as well as third-party actions taken to contain its spread and mitigate its public health effects. Therefore, management cannot estimate the potential future impact to financial position, results of operations and cash flows, but the impacts could be material.

Voluntary Retirement Incentive Program

In June 2020, AEP announced a voluntary retirement incentive program. Eligible employees volunteered for retirement from the date of the announcement through July 6, 2020, with most having an effective retirement date of August 1, 2020. Participating employees were eligible to receive up to six months base pay and a medical premium subsidy. Certain participating employees were also eligible to receive a long-term incentive plan grant, with immediate vesting, of AEP common shares. A total of 200 employees participated in the voluntary retirement program. In August 2020, AEP recorded a charge to expense of $13 million primarily related to lump sum salary payments and cash subsidies. AEP also recorded a charge to expense of $5 million related to the incremental Long-Term Incentive Plan grants issued related to this initiative. Approximately 92% of the expense was within the AEPSC and was allocated among affiliated entities including the Registrant Subsidiaries. The impact of this program was immaterial on the Registrants' financial statements as of September 30, 2020.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Three Months Ended September 30,			
	2020		2019	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 748.6		$ 733.5	
Weighted Average Number of Basic Shares Outstanding	496.2	$ 1.51	493.8	$ 1.49
Weighted Average Dilutive Effect of Stock-Based Awards	1.3	(0.01)	1.7	(0.01)
Weighted Average Number of Diluted Shares Outstanding	497.5	$ 1.50	495.5	$ 1.48

	Nine Months Ended September 30,			
	2020		2019	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,764.6		$ 1,767.6	
Weighted Average Number of Basic Shares Outstanding	495.5	$ 3.56	493.6	$ 3.58
Weighted Average Dilutive Effect of Stock-Based Awards	1.4	(0.01)	1.5	(0.01)
Weighted Average Number of Diluted Shares Outstanding	496.9	$ 3.55	495.1	$ 3.57

Equity Units are potentially dilutive securities but were excluded from the calculation of diluted EPS for the three and nine months ended September 30, 2020 and 2019, as the dilutive stock price thresholds were not met. See Note 12 - Financing Activities for more information related to Equity Units.

There were no antidilutive shares outstanding as of September 30, 2020 and 2019.

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

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

Reconciliation of Cash, Cash Equivalents and Restricted Cash

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

	September 30, 2020		
	AEP	AEP Texas	APCo
	(in millions)		
Cash and Cash Equivalents	$ 409.7	$ 0.1	$ 3.9
Restricted Cash	54.1	44.8	9.3
Total Cash, Cash Equivalents and Restricted Cash	$ 463.8	$ 44.9	$ 13.2

	December 31, 2019		
	AEP	AEP Texas	APCo
	(in millions)		
Cash and Cash Equivalents	$ 246.8	$ 3.1	$ 3.3
Restricted Cash	185.8	154.7	23.5
Total Cash, Cash Equivalents and Restricted Cash	$ 432.6	$ 157.8	$ 26.8

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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. The assessment is performed separately by each participating AEP subsidiary, which inherently contemplates any differences in geographical risk characteristics for the allowance. 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 based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified. In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for uncollectible accounts should be further adjusted in accordance with the accounting guidance for "Credit Losses." Management's assessments contemplate expected losses over the life of the accounts receivable.

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 2016-13 "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.

New standard implementation activities included: (a) the identification and evaluation of the population of financial instruments within the AEP system that are subject to the new standard, (b) the development of supporting valuation models to also contemplate appropriate metrics for current and supportable forecasted information and (c) the development of disclosures to comply with the requirements of ASU 2016-13. 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 adopted ASU 2016-13 and its related implementation guidance effective January 1, 2020, by means of an immaterial cumulative-effect adjustment to Retained Earnings on 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.

ASU 2020-04 "Reference Rate Reform: Facilitation of the Effects of Reference Rate Reform on Financial Reporting" (ASU 2020-04)

In March 2020, the FASB issued ASU 2020-04 providing guidance to ease the potential burden in accounting for Reference Rate Reform on financial reporting. The new standard is elective and applies to all entities, subject to meeting certain criteria, that have contracts, hedging relationships, and other transactions that reference the London Interbank Offered Rate (LIBOR) or another reference rate expected to be discontinued because of Reference Rate Reform. The new standard establishes a general contract modification principle that entities can apply in other areas that may be affected by Reference Rate Reform and certain elective hedge accounting expedients. Under the new standard, an entity may make a one-time election to sell or to transfer to the available-for-sale or trading classifications (or both sell and transfer), debt securities that both reference an affected rate, and were classified as held-to-maturity before January 1, 2020.

The new accounting guidance is effective for all entities as of March 12, 2020 through December 31, 2022. The amendments may be applied to contract modifications as of any date from the beginning of an interim period that includes or is subsequent to March 12, 2020, or prospectively from a date within an interim period that includes or is subsequent to March 12, 2020, up to the date that the financial statements are available to be issued. The amendments may be applied to eligible hedging relationships existing as of the beginning of the interim period that includes March 12, 2020 and to new eligible hedging relationships entered into after the beginning of the interim period that includes March 12, 2020. The one-time election to sell, transfer, or both sell and transfer debt securities classified as held-to-maturity may be made at any time after March 12, 2020 but no later than December 31, 2022. Management has yet to apply the amendments in the new standard to any contract modifications, hedging relationships, or debt securities. Management is analyzing the impact of this new standard and at this time, cannot estimate the impact of adoption on results of operations, financial position or cash flows.

3. COMPREHENSIVE INCOME

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

Presentation of Comprehensive Income

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

AEP

Three Months Ended September 30, 2020	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of June 30, 2020	$ (81.4)	$ (55.3)	$ (36.2)	$ (172.9)
Change in Fair Value Recognized in AOCI	10.2	1.9 (a)	—	12.1
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	(0.1)	—	—	(0.1)
Purchased Electricity for Resale (b)	33.3	—	—	33.3
Interest Expense (b)	—	1.3	—	1.3
Amortization of Prior Service Cost (Credit)	—	—	(4.9)	(4.9)
Amortization of Actuarial (Gains) Losses	—	—	2.6	2.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	33.2	1.3	(2.3)	32.2
Income Tax (Expense) Benefit	7.1	0.2	(0.5)	6.8
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	26.1	1.1	(1.8)	25.4
Net Current Period Other Comprehensive Income (Loss)	36.3	3.0	(1.8)	37.5
Balance in AOCI as of September 30, 2020	$ (45.1)	$ (52.3)	$ (38.0)	$ (135.4)

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

AEP

Nine Months Ended September 30, 2020	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of December 31, 2019	$ (103.5)	$ (11.5)	$ (32.7)	$ (147.7)
Change in Fair Value Recognized in AOCI	(48.6)	(43.6) (a)	—	(92.2)
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	(0.3)	—	—	(0.3)
Purchased Electricity for Resale (b)	135.7	—	—	135.7
Interest Expense (b)	—	3.6	—	3.6
Amortization of Prior Service Cost (Credit)	—	—	(14.4)	(14.4)
Amortization of Actuarial (Gains) Losses	—	—	7.7	7.7
Reclassifications from AOCI, before Income Tax (Expense) Benefit	135.4	3.6	(6.7)	132.3
Income Tax (Expense) Benefit	28.4	0.8	(1.4)	27.8
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	107.0	2.8	(5.3)	104.5
Net Current Period Other Comprehensive Income (Loss)	58.4	(40.8)	(5.3)	12.3
Balance in AOCI as of September 30, 2020	$ (45.1)	$ (52.3)	$ (38.0)	$ (135.4)

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

AEP Texas

Three Months Ended September 30, 2020		Cash Flow Hedge – Interest Rate		Pension and OPEB		Total
				(in millions)		
Balance in AOCI as of June 30, 2020	$	(2.9)	$	(9.3)	$	(12.2)
Change in Fair Value Recognized in AOCI		—		—		—
Amount of (Gain) Loss Reclassified from AOCI						
Interest Expense (b)		0.4		—		0.4
Amortization of Prior Service Cost (Credit)		—		(0.1)		(0.1)
Amortization of Actuarial (Gains) Losses		—		0.1		0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit		0.4		—		0.4
Income Tax (Expense) Benefit		0.1		—		0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		0.3		—		0.3
Net Current Period Other Comprehensive Income (Loss)		0.3		—		0.3
Balance in AOCI as of September 30, 2020	$	(2.6)	$	(9.3)	$	(11.9)

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

Nine Months Ended September 30, 2020		Cash Flow Hedge – Interest Rate		Pension and OPEB		Total
				(in millions)		
Balance in AOCI as of December 31, 2019	$	(3.4)	$	(9.4)	$	(12.8)
Change in Fair Value Recognized in AOCI		—		—		—
Amount of (Gain) Loss Reclassified from AOCI						
Interest Expense (b)		1.0		—		1.0
Amortization of Prior Service Cost (Credit)		—		(0.1)		(0.1)
Amortization of Actuarial (Gains) Losses		—		0.2		0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit		1.0		0.1		1.1
Income Tax (Expense) Benefit		0.2		—		0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit		0.8		0.1		0.9
Net Current Period Other Comprehensive Income (Loss)		0.8		0.1		0.9
Balance in AOCI as of September 30, 2020	$	(2.6)	$	(9.3)	$	(11.9)

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

APCo

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2020	$ (4.1)	$ 2.2	$ (1.9)
Change in Fair Value Recognized in AOCI	0.7	—	0.7
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.2)	—	(0.2)
Amortization of Prior Service Cost (Credit)	—	(1.3)	(1.3)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.2)	(1.2)	(1.4)
Income Tax (Expense) Benefit	(0.1)	(0.3)	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.1)	(0.9)	(1.0)
Net Current Period Other Comprehensive Income (Loss)	0.6	(0.9)	(0.3)
Balance in AOCI as of September 30, 2020	$ (3.5)	$ 1.3	$ (2.2)

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

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ 0.9	$ 4.1	$ 5.0
Change in Fair Value Recognized in AOCI	(3.8)	—	(3.8)
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.8)	—	(0.8)
Amortization of Prior Service Cost (Credit)	—	(4.0)	(4.0)
Amortization of Actuarial (Gains) Losses	—	0.4	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.8)	(3.6)	(4.4)
Income Tax (Expense) Benefit	(0.2)	(0.8)	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.6)	(2.8)	(3.4)
Net Current Period Other Comprehensive Income (Loss)	(4.4)	(2.8)	(7.2)
Balance in AOCI as of September 30, 2020	$ (3.5)	$ 1.3	$ (2.2)

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

I&M

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2020	$ (9.1)	$ (1.7)	$ (10.8)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.3)	(0.3)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	(0.1)	0.4
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	(0.1)	0.3
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.1)	0.3
Balance in AOCI as of September 30, 2020	$ (8.7)	$ (1.8)	$ (10.5)

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

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ (9.9)	$ (1.7)	$ (11.6)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	(0.6)	(0.6)
Amortization of Actuarial (Gains) Losses	—	0.5	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.5	(0.1)	1.4
Income Tax (Expense) Benefit	0.3	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.2	(0.1)	1.1
Net Current Period Other Comprehensive Income (Loss)	1.2	(0.1)	1.1
Balance in AOCI as of September 30, 2020	$ (8.7)	$ (1.8)	$ (10.5)

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

OPCo

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of June 30, 2020	$ —
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—
Net Current Period Other Comprehensive Income (Loss)	—
Balance in AOCI as of September 30, 2020	$ —

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

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2019	$ —
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—
Net Current Period Other Comprehensive Income (Loss)	—
Balance in AOCI as of September 30, 2020	$ —

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

PSO

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of June 30, 2020	$ 0.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(0.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.3)
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.3)
Net Current Period Other Comprehensive Income (Loss)	(0.3)
Balance in AOCI as of September 30, 2020	$ 0.3

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

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2019	$ 1.1
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.0)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.0)
Income Tax (Expense) Benefit	(0.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of September 30, 2020	$ 0.3

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

SWEPCo

Three Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2020	$ (1.1)	$ (0.2)	$ (1.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Amortization of Actuarial (Gains) Losses	—	—	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	(0.5)	—
Income Tax (Expense) Benefit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	(0.4)	—
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.4)	—
Balance in AOCI as of September 30, 2020	$ (0.7)	$ (0.6)	$ (1.3)

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

SWEPCo

Nine Months Ended September 30, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2019	$ (1.8)	$ 0.5	$ (1.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.4	—	1.4
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.4	(1.4)	—
Income Tax (Expense) Benefit	0.3	(0.3)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.1	(1.1)	—
Net Current Period Other Comprehensive Income (Loss)	1.1	(1.1)	—
Balance in AOCI as of September 30, 2020	$ (0.7)	$ (0.6)	$ (1.3)

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

(a) The change in fair value includes $(1) million and $6 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the three and nine months ended September 30, 2020, respectively.
(b) Amounts reclassified to the referenced line item on the statements of income.
(c) The change in fair value includes $2 million and $6 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the three and nine months ended September 30, 2019, respectively.

4. RATE MATTERS

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

As discussed in the 2019 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2019 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2020 and updates the 2019 Annual Report.

Regulated Generating Units to be Retired (Applies to AEP, PSO and SWEPCo)

In September 2018, management announced that the Oklaunion Power Station was probable of abandonment and was expected to be retired.The Oklaunion Power Station was retired in September 2020. PSO will seek recovery of the Oklaunion Power Station in its next base rate caseIn October 2020, the Oklaunion Power Station site was sold to a non-affiliated third-party. See "Oklaunion Power Station" section of Note 6 for additional information.

In January 2020, as part of the 2019 Arkansas Base Rate Case, management announced that the Dolet Hills Power Station was probable of abandonment and was to be retired by December 2026. In March 2020, management announced plans to retire the plant in 2021.

The table below summarizes the plant investment and their cost of removal, currently being recovered, as well as the regulatory assets for accelerated depreciation for the generating units as of September 30, 2020.

Plant	Gross Investment Including CWIP	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	$ —	$ —	$ —	$ 38.0	(a)	$ 3.4	$ 5.2	2020	27 years
Dolet Hills Power Station	346.7	250.0	$ 96.7	50.4	(b)	5.8	24.0	2021	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.
(b) In January 2020, SWEPCo changed depreciation rates to utilize the 2026 end-of-life and defer depreciation expense to a regulatory asset for the amount in excess of the previously APSC-approved depreciation rates for Dolet Hills Power Station. In March 2020, SWEPCo changed depreciation rates again to utilize the accelerated 2021 end-of-life.

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.DHLC provides100% of the fuel supply to Dolet Hills Power Station.After careful consideration of current economic conditions, and particularly for the benefit of their customers, management of SWEPCo and CLECO determined DHLC would not proceed developing additional Oxbow Lignite Company (Oxbow) mining areas for future lignite extraction and ceased extraction of lignite at the mine in May 2020. Based on these actions, management revised the estimated useful life of DHLC's and Oxbow's assets to coincide with the date at which extraction was discontinued in the second quarter of 2020 and the date at which delivery of lignite is expected to cease in September 2021. Management also revised the useful life of the Dolet Hills Power Station to 2021 based on the remaining estimated fuel supply available for continued seasonal operation. In March 2020, primarily due to the revision in the useful life of DHLC, SWEPCo recorded a revision to increase estimated ARO liabilities by $21 million. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining.

The Dolet Hills Power Station costs are recoverable by SWEPCo through base ratesSWEPCo's share of the net investment in the Dolet Hills Power Station is $153 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 September 30, 2020, DHLC has unbilled lignite inventory and fixed costs of $36 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. In 2009, SWEPCo acquired interests in 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 September 30, 2020, Oxbow has unbilled fixed costs of $10 million that will be billed to SWEPCo prior to the closure of the Dolet Hills Power Station. DHLC and Oxbow have billed SWEPCo $111 million for lignite deliveries from April 2020 through September 2020, which primarily includes accelerated depreciation and amortization of fixed costs. 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.

In October 2020, SWEPCo filed a request with the LPSC for recovery of the Louisiana share of these additional fuel costs. SWEPCo's filing proposes to defer $36 million of fuel costs in 2021 and recover the deferral plus carrying costs over five years beginning in 2022.

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

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

	AEP	
	September 30, 2020	**December 31, 2019**
Noncurrent Regulatory Assets	**(in millions)**	
Regulatory Assets Currently Earning a Return		
Dolet Hills Power Station Accelerated Depreciation	$ 50.4	$ —
Kentucky Deferred Purchase Power Expenses	38.5	30.2
Oklaunion Power Station Accelerated Depreciation	38.0	27.4
Plant Retirement Costs – Unrecovered Plant	35.2	35.2
COVID-19	2.0	—
Other Regulatory Assets Pending Final Regulatory Approval	2.2	0.7
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	86.3	7.2
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	30.1
COVID-19	20.3	—
Asset Retirement Obligation	8.7	7.2
Vegetation Management Program (a)	3.8	29.4
Cook Plant Study Costs (b)	—	7.6
Other Regulatory Assets Pending Final Regulatory Approval	5.3	6.7
Total Regulatory Assets Pending Final Regulatory Approval (c)	$ 316.6	$ 181.7

(a) In April 2020, $26 million of deferred expenses were approved for recovery. See "2019 Texas Base Rate Case" section below for additional information.
(b) Approved for recovery in the first quarter of 2020 in the Indiana Base Rate Case.
(c) APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with AMI meters. As of September 30, 2020 and December 31, 2019, APCo has approximately $32 million and $51 million, respectively, of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo is pursuing full recovery of these assets through its Virginia depreciation rates. See "2017-2019 Virginia Triennial Review" section below for additional information.

Noncurrent Regulatory Assets	AEP Texas	
	September 30, 2020	December 31, 2019
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
COVID-19	$ 10.9	$ —
Vegetation Management Program (a)	3.8	29.4
Other Regulatory Assets Pending Final Regulatory Approval	1.4	1.4
Total Regulatory Assets Pending Final Regulatory Approval	$ 16.1	$ 30.8

(a) In April 2020, $26 million of deferred expenses were approved for recovery. See “2019 Texas Base Rate Case” section below for additional information.

Noncurrent Regulatory Assets	APCo	
	September 30, 2020	December 31, 2019
	(in millions)	
Regulatory Assets Currently Earning a Return		
COVID-19 – Virginia	$ 2.0	$ —
Plant Retirement Costs – Materials and Supplies	—	0.5
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	30.1
COVID-19 – West Virginia	0.8	—
Total Regulatory Assets Pending Final Regulatory Approval (a)	$ 28.7	$ 30.6

(a) APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with AMI meters. As of September 30, 2020 and December 31, 2019, APCo has approximately $2 million and $51 million, respectively, of Virginia jurisdictional AMR meters recorded in Total Property, Plant and Equipment - Net on its balance sheets.APCo is pursuing full recovery of these assets through its Virginia depreciation rates. See “2017-2019 Virginia Triennial Review” section below for additional information.

Noncurrent Regulatory Assets	I&M	
	September 30, 2020	December 31, 2019
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
COVID-19	$ 3.1	$ —
Cook Plant Study Costs (a)	—	7.6
Other Regulatory Assets Pending Final Regulatory Approval	—	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$ 3.1	$ 7.7

(a) Approved for recovery in the first quarter of 2020 in the Indiana Base Rate Case.

Noncurrent Regulatory Assets	OPCo	
	September 30, 2020	December 31, 2019
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 3.6	$ —
COVID-19	2.9	—
Other Regulatory Assets Pending Final Regulatory Approval	0.1	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$ 6.6	$ 0.1

Noncurrent Regulatory Assets	PSO	
	September 30, 2020	December 31, 2019
	(in millions)	
Regulatory Assets Currently Earning a Return		
Oklaunion Power Station Accelerated Depreciation	$ 38.0	$ 27.4
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	9.4	7.2
COVID-19	0.3	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 47.7	$ 34.6

Noncurrent Regulatory Assets	SWEPCo	
	September 30, 2020	December 31, 2019
	(in millions)	
Regulatory Assets Currently Earning a Return		
Dolet Hills Power Station Accelerated Depreciation	$ 50.4	$ —
Plant Retirement Costs – Unrecovered Plant, Louisiana	35.2	35.2
Other Regulatory Assets Pending Final Regulatory Approval	2.2	0.2
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs - Louisiana	67.3	—
Asset Retirement Obligation - Louisiana	8.5	7.2
COVID-19	1.7	—
Other Regulatory Assets Pending Final Regulatory Approval	2.0	3.7
Total Regulatory Assets Pending Final Regulatory Approval	$ 167.3	$ 46.3

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

COVID-19 Pandemic

During the first quarter of 2020, AEP's electric operating companies informed both retail customers and state regulators that disconnections for non-payment were temporarily suspended. Shortly thereafter, AEP's state regulators also imposed temporary moratoria on customary disconnection practices. During the third and the fourth quarter of 2020, certain state regulators began to lift restrictions on disconnects. As of September 30, 2020, AEP resumed disconnections in its regulated jurisdictions with the exception of Virginia, West Virginia, Kentucky, Arkansas, Louisiana and Tennessee. AEP's electric operating companies continue to work with regulators and stakeholders in these states and management currently anticipates resuming customary disconnection practices in the fourth quarter of 2020. However, this timing could change if there is new legislation or other regulatory directives issued in the future. Continuing adverse economic conditions may result in the inability of customers to pay for electric service, which could affect revenue recognition and the collectability of accounts receivable. The

Registrants have worked with their state commissions to achieve deferral authority for incremental expenses incurred due to COVID-19.All of AEP's regulated jurisdictions have issued initial COVID-19 orders with the exception of Tennessee.If any costs related to COVID-19 are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 $6 million annual increase in rates based upon a proposed 10.5% ROE.The filing included 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 sought a prudence determination on all transmission and distribution capital additions through 2018 included in interim rates from 2008 to December 2019.

In April 2020, the PUCT issued an order approving a stipulation and settlement agreement.The order includes an annual base rate reduction of $40 million based upon a 9.4% ROE with a capital structure of57.5% debt and 42.5% common equity effective with the first billing cycle in June 2020. The order provides recovery of $26 million in capitalized vegetation management expenses that were incurred through 2018. The order 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. The order requires AEP Texas to file its next base rate case within four years of the date of that the final order was issued. The order also states future financially based capital incentives will not be included in interim transmission and distribution rates and contains various ring-fencing provisions. As a result of the final order, 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.

In December 2019, as a result of the initial stipulation and settlement agreement, AEP Texas (a) recorded an impairment of $33 million related to capital investments, which included $10 million of 2019 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.

AEP Texas Interim Transmission and Distribution Rates

Through September 30, 2020, AEP Texas' cumulative revenues from interim base rate increases that are subject to review is estimated to be $38 million. A base rate review could result in a refund to customers if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition. AEP Texas is required to file for a comprehensive rate review no later than April 3, 2024.

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

2017-2019 Virginia Triennial Review

Amendments to Virginia law impacting investor-owned utilities were enacted, effective July 1, 2018, that required APCo to file a 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 the Virginia jurisdictional share of these plants was $93 million before cost of removal, including materials and supplies inventory and ARO balances. 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. As a result, management deems these costs to be substantially recovered by APCo during the triennial review period.

In March 2020, APCo submitted its 2017-2019 Virginia triennial earnings review filing and base rate case with the Virginia SCC as required by state law. APCo requested a $65 million annual increase in base rates based upon a proposed 9.9% ROE. The requested annual increase includes $19 million related to depreciation for updated test year end depreciable balances and a proposed increase in APCo's Virginia depreciation rates and $8 million related to APCo's calculated shortfall in 2017-2019 APCo's Virginia earnings. Inclusive of the Virginia jurisdictional share of the $93 million expense associated with APCo's retired coal-fired generation assets, APCo calculated its 2017-2019 Virginia earnings for the triennial period to be below the authorized ROE range.

APCo is currently in the process of retiring and replacing its Virginia jurisdictional Automated Meter Reading (AMR) meters with AMI meters. As of September 30, 2020 and December 31, 2019, APCo has approximately $52 million and $51 million of Virginia jurisdictional AMR meters as well as $82 million and $75 million of Virginia jurisdictional AMI meters recorded in Total Property, Plant and Equipment - Net on its balance sheets. APCo is pursuing full recovery of these assets through its Virginia depreciation rates as discussed above.

In July 2020, a certain intervenor filed testimony asserting that APCo had a revenue surplus of $23 million for its filed rate year based upon the intervenor's recommended ROE of 8.75%. The intervenor also filed proposed adjustments to APCo's requested revenue requirement including: (a) a reduction to depreciation expense to reflect a 2040 retirement date for Amos Plant instead of 2032 for Amos Units 1 and 2 and 2033 for Amos Unit 3 as proposed by APCo, (b) removal of AMI meters from rate base along with related depreciation and (c) a reduction of purchased power expense related to OVEC demand charges. This intervenor, along with one other intervenor, also proposed the removal of major storm expenses.

In addition, this certain intervenor submitted corrected testimony contending APCo's earned return for the triennial period was 11.12%, which equates to a potential refund to customers of $34 million. The intervenor also filed a separate legal memorandum opposing the inclusion of the 2019 expensing of the retired coal-fired generation assets from APCo's 2017-2019 earnings test results. The testimony also removed the related rate base associated with the retired coal units. Another intervenor recommended that APCo not earn a return on $114 million of prepaid pension and OPEB assets.

In August and September 2020, the Virginia staff filed testimony supporting an annual APCo Virginia jurisdictional revenue deficiency of $17 million based upon an ROE of 8.73%. However, Virginia staff contends APCo's earned return for the triennial period was 9.55%, which is above the 9.42% midpoint of APCo's authorized ROE range. Based on Virginia law, a Virginia SCC order finding an earned ROE above the midpoint would prevent APCo from receiving a prospective increase in Virginia retail rates. In addition, the staff recommended that APCo: (a) reverse the pretax Virginia jurisdictional share of the $93 million expense recorded in December 2019 for its retired coal-fired generation assets and instead amortize the retired assets over a 10-year period beginning in 2015, (b) implement 2017 depreciation study rates, effective January 2018, which would increase depreciation expense by $18 million and $20 million in 2018 and 2019, respectively (including $5 million annually related to transmission), (c) implement 2019 depreciation study rates, effective January 2020, which would increase depreciation expense by $29 million annually (including $11 million related to transmission) starting January 1, 2020 and (d) remove $9 million of major storm expenses and $12 million of coal combustion by-product expenses from the requested annual increase in base rates.

APCo expects to receive an order in November 2020. If any APCo Virginia jurisdictional costs are not recoverable or if refunds of revenues collected from customers during the triennial review period are ordered by the Virginia SCC, it could reduce future net income and cash flows and impact financial condition.

West Virginia ENEC and Vegetation Management Riders

In June 2020, the WVPSC issued an order directing APCo and WPCo to increase rider rates relating to ENEC and vegetation management by combined $101 million ($81 million related to APCo) over twelve months beginning September 2020. This increase will be partially offset by a refund of $38 million ($31 million related to APCo) of Excess ADIT that is not subject to normalization requirements over ten months beginning September 2020. These transactions will result in no overall impact to net income.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next base rate proceeding. Through September 30, 2020, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $1.1 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)

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 was based upon a proposed 10.5% ROE. The proposed annual increase included $78 million related to a proposed annual increase in depreciation expense. The requested annual increase in depreciation expense included $52 million related to proposed investments and $26 million related to increased depreciation rates. The request included the continuation of all existing riders and a new AMI rider for proposed meter projects.

In March 2020, the IURC issued an order approving a phased-in increase in base rates of up to $77 million based upon an ROE of 9.7%. This approved phase-in increase includes: (a) an annual increase in base rates of $44 million effective March 2020 and (b) an annual increase in base rates of up to $77 million, effective January 2021, based on the IURC-approved forecast of December 31, 2020 Indiana jurisdictional electric plant in service. A compliance filing will be made in January 2021 to adjust the final rate increase to reflect the lower of I&M's actual or IURC-approved Indiana jurisdictional electric plant in service balance as of December 31, 2020. The order also approved the majority of I&M's proposed changes in depreciation as well as the test year level of AMI deployment, but did not approve a cost recovery rider for AMI investments made in subsequent years. The order rejected I&M's proposed re-allocation of capacity costs related to the loss of a significant FERC wholesale contract, which will negatively impact I&M's annual pretax earnings by approximately $20 million starting June 2020.

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

Kentucky Tax Reform

In May 2020, KPCo filed a request with the KPSC to issue a one-time refund of Excess ADIT that is not subject to normalization requirements to customers of approximately $11 million to eliminate certain customer delinquencies attributable to the COVID-19 pandemic. In October 2020, the KPSC denied KPCo's request.

2020 Kentucky Base Rate Case

In June 2020, KPCo filed a request with the KPSC for a $65 million net annual increase in base rates based upon a proposed 10% ROE with the increase to be implemented no earlier than January 2021. The filing proposes that KPCo would offset the first year of rate increases by refunding Excess ADIT that is not subject to normalization requirements to customers. Additionally, KPCo requested recovery of the previously authorized deferral of $50 million of Rockport Plant Unit Power Agreement expenses and related carrying charges over a 5-year period beginning in December 2022, through an existing purchased power rider.

In October 2020, various intervenors filed testimony recommending annual rate increases ranging from $0 to $17 million based upon a ROE ranging from 8.93% to 9.25%. Other differences between KPCo's requested annual base rate increase and the intervenors' recommendations are primarily due to: (a) a proposed change in the recovery period of Rockport Plant, Unit 2 SCR depreciation expense from three to ten years, (b) a proposal to remove certain employee-related expenses from the revenue requirement and (c) a recommendation that KPCo not earn a return on $64 million of prepaid pension and OPEB assets. In addition, intervenors expressed opposition to: (a) KPCo's proposed recovery/return of certain annual PJM Open Access Transmission Tariff expenses below/above the corresponding level recovered in base rates through an existing rider, (b) deployment of AMI with cost recovery through a new rider and (c) KPCo's proposed changes to its net metering tariff. KPCo will file rebuttal testimony in November 2020. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

2020 Ohio Base Rate Case

In June 2020, OPCo filed a request with the PUCO for a $42 million annual increase in base rates based upon a proposed 10.15% ROE net of existing riders. Additionally, OPCo filed a request with the PUCO for a 60-day temporary delay of the normal rate case proceeding due to the COVID-19 pandemic with rates expected to be effective approximately mid-2021. If any of the requested costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2019 Ohio DIR Audit

OPCo conducts business under an Electric Security Plan as approved by the PUCO which subjects the DIR to annual audits. In August 2020, a third-party consulting company filed an audit report with the PUCO indicating that OPCo exceeded its 2019 authorized revenue limit by $7 million. Management disagrees with the audit results and believes that OPCo was below its authorized revenue limit in 2019. The PUCO has not yet issued a procedural schedule to address the audit results. If the results of the audit are upheld by the PUCO and any refunds to customers or revenue reductions are ordered, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters (Applies to AEP and SWEPCo)

2012 Texas Base Rate Case

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

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of a previously recorded regulatory disallowance in 2013. The resulting annual base rate increase was approximately $52 million. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. In the fourth quarter of 2019 and first quarter of 2020, SWEPCo and various intervenors filed briefs with the Texas Supreme Court. In August 2020, the Texas Supreme Court granted SWEPCo's petition for review and oral arguments were scheduled for December 2020.

As of September 30, 2020, the net book value of Turk Plant was $1.4 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% ROE. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a ROE 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 through a tax rider that will end when the Excess ADIT not subject to normalization requirements is fully refunded to customers which is currently estimated to be July 2020.

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. In July 2020, the LPSC issued an order approving an unopposed stipulation and settlement agreement for a one-time refund of $6 million over three months beginning in August 2020.

Hurricane Laura

In August 2020, Hurricane Laura hit the coasts of Louisiana and Texas, causing power outages to more than 130,000 customers across SWEPCo's service territories. Prior to Hurricane Laura, SWEPCo did not have a catastrophe reserve or automatic deferral authority within any of its jurisdictions. In October 2020, the LPSC issued an order allowing Louisiana utilities, including SWEPCo, to establish a regulatory asset to track and defer expenses associated with Hurricane Laura. In October 2020, as part of the 2020 Texas Base Rate Case, SWEPCo requested deferral authority of incremental other operation and maintenance expenses. SWEPCo is currently evaluating recovery options for the storm damage in its Arkansas jurisdiction. As of September 30, 2020, management estimates that SWEPCo has incurred incremental other operation and maintenance expenses of $69 million ($67 million of which has been deferred as a regulatory asset related to the Louisiana jurisdiction) and incremental capital expenditures of $31 million ($30 million related to the Louisiana jurisdiction). If any costs related to Hurricane Laura are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Hurricane Delta

In October 2020, Hurricane Delta hit the coast of Louisiana, causing power outages to more than 23,000 customers in SWEPCo's Louisiana jurisdiction. Management currently estimates that SWEPCo has incurred incremental other operation and maintenance expenses ranging from $10 million to $18 million and incremental capital expenditures of up to $6 million. SWEPCo will seek deferral authority of incremental other operation and maintenance expenses from the LPSC. If any costs related to Hurricane Delta are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2020 Texas Base Rate Case

In October 2020, SWEPCo filed a request with the PUCT for a $105 million annual increase in Texas base rates based upon a proposed 10.35% ROE. The request would move transmission and distribution interim revenues recovered through riders into base rates. Eliminating these riders would result in a net annual requested base rate increase of $90 million primarily due to increased investments. The proposed net annual increase: (a) includes $5 million related to vegetation management to maintain and improve the reliability of its Texas jurisdictional distribution system, (b) requests a $10 million annual depreciation increase and (c) seeks $2 million annually to establish a storm catastrophe reserve. In addition, SWEPCo also requested recovery of the Texas jurisdictional share of the Dolet Hills Power Station of $45 million which is expected to be retired by the end of 2021. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC Rate Matters

AFUDC Waiver **(Applies to all Registrants except AEP Texas)**

In June 2020, FERC granted a temporary waiver providing utilities the option to elect to modify the existing AFUDC rate calculations in response to the COVID-19 pandemic.As a result of the waiver, the AFUDC formula for the 12-month period starting with March 2020 may be calculated using the simple average of the actual historical short-term debt balances for 2019, instead of current period short-term balances. All other aspects of the AFUDC formula remained unchanged. AEP subsidiaries including certain Registrant Subsidiaries elected to apply the waiver in July 2020.The impact upon election was immaterial on the Registrants’ financial statements.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2019 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit (Applies to AEP and AEP Texas)

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

AEP has a $4 billion revolving credit facility due in June 2022, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of September 30, 2020, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $405 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2020 were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 197.3	October 2020 to August 2021
AEP Texas	2.2	July 2021

Guarantees of Equity Method Investees (Applies to AEP)

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

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2020, 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 activit 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.

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of September 30, 2020, 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	$ 49.8
AEP Texas	11.4
APCo	6.8
I&M	4.5
OPCo	7.9
PSO	4.6
SWEPCo	5.2

Rockport Lease (Applies to AEP and I&M)

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The Owner Trustee owns the Plant and leases equal portions to AEGCo and I&M. The lease is accounted for as an operating lease. The lease term is for 33 years and at the end of the lease term, AEGCo and I&M have the option to renew the lease at a rate that approximates fair value. The option to renew was not included in the measurement of the lease obligation as of September 30, 2020 as the execution of the option was not reasonably certain. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt.

The future minimum lease payments for this sale-and-leaseback transaction as of September 30, 2020 were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2020	$ 73.9	$ 37.0
2021	147.8	73.9
2022	147.5	73.7
Total Future Minimum Lease Payments	$ 369.2	$ 184.6

(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 September 30, 2020, the maximum potential amount of future payments required under the guaranteed leases was $50 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 September 30, 2020, AEP's boat and barge lease guarantee liability was $3 million, of which $1 million was recorded in Other Current Liabilities and $2 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. In March 2020, the bankruptcy court approved the party's recapitalization plan. In April 2020, the nonaffiliated party emerged from bankruptcy. 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.

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

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

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. The Registrants currently incur costs to dispose of these substances safely. For remediation processes not specifically discussed, management does not anticipate that the liabilities, if any, arising from such remediation processes would have a material effect on the financial statements.

Virginia House Bill 443 (Applies to AEP and APCo)

In March 2020, Virginia's Governor signed House Bill 443 (HB 443), effective July 2020, requiring APCo to close certain ash disposal units at the retired Glen Lyn Station by removal of all coal combustion material. As a result, in June 2020, APCo recorded a $199 million revision to increase estimated Glen Lyn Station ash disposal ARO liabilities. The closure is required to be completed within 15 years from the start of the excavation process. HB 443 provides for the recovery of all costs associated with closure by removal through the Virginia environmental rate adjustment clause (E-RAC). APCo may begin recovering these costs through the E-RAC beginning July 1, 2022. APCo is permitted to record carrying costs on the unrecovered balance of closure costs at a weighted average cost of capital approved by the Virginia SCC. HB 443 also allows any closure costs allocated to non-Virginia jurisdictional customers, but not collected from such non-Virginia jurisdictional customers, to be recovered from Virginia jurisdictional customers through the E-RAC.

NUCLEAR CONTINGENCIES (Applies to AEP and I&M)

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

OPERATIONAL CONTINGENCIES

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

In 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering, refueling or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

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

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

Thereafter, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree. The district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. The consent decree was modified based on an agreement among the parties in July 2019. The district court's stay of the lease litigation expired in August 2020. Upon expiration of the stay, plaintiffs filed a motion for partial summary judgment, arguing that the consent decree violates the facility lease and the participation agreement and requesting that the district court enter a judgment for the plaintiffs on their breach of contract claim. AEP's memorandum in opposition was filed in October 2020. All deadlines, including discovery, are stayed, pending resolution of the motion.

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 (Applies to AEP, AEP Texas and SWEPCo)

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. In July 2020, plaintiffs amended the complaint to add three new patents. The amended complaint seeks injunctive relief and damages. The case is scheduled for trial in January 2023. 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; 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. The denial of those claims was appealed to the AEP System Retirement Plan Appeal Committee and the Committee upheld the denial of claims. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Litigation Related to Ohio House Bill 6

In August 2020, an AEP shareholder filed a putative class action lawsuit in the United States District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. The complaint alleges misrepresentations or omissions by AEP regarding: (a) its alleged participation in public corruption with respect to the passage of Ohio House Bill 6, (b) its regulatory, legislative and lobbying activities in Ohio and (c) its clean energy strategy. The complaint seeks monetary damages among other forms of relief. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

6. ACQUISITIONS AND DISPOSITIONS

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

ACQUISITIONS

Sempra Renewables LLC (Generation & Marketing Segment)

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation and battery assets valued at approximately $1.1 billion. This acquisition is part of AEP's strategy to grow its renewable generation portfolio and to diversify generation resources. AEP paid $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.

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.

Parent has issued guarantees over the performance of the joint ventures. If a joint venture were to default on payments or performance, Parent would be required to make payments on behalf of the joint venture. As of September 30, 2020, the maximum potential amount of future payments associated with these guarantees was $166 million, with the last guarantee expiring in December 2037. The non-contingent liability recorded associated with these guarantees was $31 million, with an additional $1 million expected credit loss liability for the contingent portion of the guarantees. Management considered historical losses, economic conditions, and reasonable and supportable forecasts in the calculation of the expected credit loss. As the joint ventures generate cash flows through PPAs, the measurement of the contingent portion of the guarantee liability is based upon assessments of the credit quality and default probabilities of the respective PPA counterparties.

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.

Desert Sky Wind Farm and Trent Wind Farm (Generation & Marketing Segment)

In August 2020, AEP exercised its call right which required the nonaffiliated member of Desert Sky Wind Farm LLC and Trent Wind Farm LLC (collectively the LLCs) to sell its noncontrolling interest to AEP. The exercise price for the call right was determined using a discounted cash flow model with agreed input assumptions as well as updates to certain assumptions reasonably expected based on the actual results of the LLCs. As a result, the LLCs are wholly-owned by AEP and management has concluded that the LLCs are no longer VIEs. AEP paid $57 million in cash, derecognized $63 million of Redeemable Noncontrolling Interest within Mezzanine Equity and recorded an increase of $6 million of Paid-In Capital on the balance sheets.

DISPOSITIONS

Conesville Plant (Generation & Marketing Segment)

In June 2020, AEP and a non-affiliated joint-owner executed an Environmental Liability and Property Transfer and Asset Purchase Agreement with a non-affiliated third-party related to the merchant Conesville Plant site. The purchaser took ownership of the assets and assumed responsibility for environmental liabilities, including ash pond closure, asbestos abatement and decommissioning and demolition of the Conesville Plant site. In consideration of the transfer of the acquired assets to the purchaser and the purchaser's assumption of liabilities, AEP will pay approximately $98 million, derecognized $106 million in ARO and recorded an immaterial gain on the transaction which is recorded in Other Operation on the statements of income. AEP paid approximately $26 million in June 2020 and will make additional payments totaling $28 million in quarterly installments from October 2020 to April 2021 and payments totaling $44 million in quarterly installments from July 2021 to July 2022.

Oklaunion Power Station (Applies to AEP, AEP Texas and PSO)

In October 2020, AEP Texas, PSO and a non-affiliated joint-owner executed an Environmental Liability and Property Transfer and Asset Purchase Agreement with a non-affiliated third-party related to the Oklaunion Power Station site.The purchaser took ownership of the assets and assumed responsibility for environmental liabilities, including ash pond closure, asbestos abatement and decommissioning and demolition of the Oklaunion Power Station site. The sale is expected to have an immaterial impact on the financial statements in the fourth quarter of 2020.

7. BENEFIT PLANS

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

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

Components of Net Periodic Benefit Cost

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

AEP

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 28.0	$ 23.8	$ 2.5	$ 2.4
Interest Cost	42.0	51.1	10.0	12.6
Expected Return on Plan Assets	(66.3)	(74.0)	(23.9)	(23.4)
Amortization of Prior Service Credit	—	—	(17.4)	(17.3)
Amortization of Net Actuarial Loss	23.5	14.4	1.4	5.5
Net Periodic Benefit Cost (Credit)	$ 27.2	$ 15.3	$ (27.4)	$ (20.2)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 84.0	$ 71.6	$ 7.5	$ 7.1
Interest Cost	125.9	153.3	29.9	37.9
Expected Return on Plan Assets	(198.7)	(222.0)	(71.8)	(70.3)
Amortization of Prior Service Credit	—	—	(52.3)	(51.8)
Amortization of Net Actuarial Loss	70.3	43.2	4.4	16.6
Net Periodic Benefit Cost (Credit)	$ 81.5	$ 46.1	$ (82.3)	$ (60.5)

AEP Texas

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 2.6	$ 2.2	$ 0.2	$ 0.1
Interest Cost	3.5	4.4	0.8	1.0
Expected Return on Plan Assets	(5.7)	(6.5)	(2.0)	(1.9)
Amortization of Prior Service Credit	—	—	(1.4)	(1.5)
Amortization of Net Actuarial Loss	1.9	1.2	0.1	0.5
Net Periodic Benefit Cost (Credit)	$ 2.3	$ 1.3	$ (2.3)	$ (1.8)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 7.6	$ 6.5	$ 0.6	$ 0.5
Interest Cost	10.5	13.1	2.4	3.0
Expected Return on Plan Assets	(17.1)	(19.4)	(6.0)	(5.8)
Amortization of Prior Service Credit	—	—	(4.4)	(4.4)
Amortization of Net Actuarial Loss	5.8	3.7	0.4	1.4
Net Periodic Benefit Cost (Credit)	$ 6.8	$ 3.9	$ (7.0)	$ (5.3)

APCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 2.7	$ 2.4	$ 0.3	$ 0.2
Interest Cost	5.0	6.3	1.6	2.2
Expected Return on Plan Assets	(8.4)	(9.4)	(3.6)	(3.7)
Amortization of Prior Service Credit	—	—	(2.5)	(2.5)
Amortization of Net Actuarial Loss	2.8	1.8	0.2	1.0
Net Periodic Benefit Cost (Credit)	$ 2.1	$ 1.1	$ (4.0)	$ (2.8)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 7.9	$ 7.1	$ 0.8	$ 0.7
Interest Cost	15.2	18.9	4.9	6.5
Expected Return on Plan Assets	(25.2)	(28.1)	(10.9)	(11.0)
Amortization of Prior Service Credit	—	—	(7.6)	(7.5)
Amortization of Net Actuarial Loss	8.4	5.3	0.7	2.8
Net Periodic Benefit Cost (Credit)	$ 6.3	$ 3.2	$ (12.1)	$ (8.5)

I&M

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 3.9	$ 3.3	$ 0.4	$ 0.3
Interest Cost	4.9	6.0	1.2	1.5
Expected Return on Plan Assets	(8.3)	(9.1)	(3.0)	(2.8)
Amortization of Prior Service Credit	—	—	(2.3)	(2.4)
Amortization of Net Actuarial Loss	2.7	1.6	0.1	0.7
Net Periodic Benefit Cost (Credit)	$ 3.2	$ 1.8	$ (3.6)	$ (2.7)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 11.6	$ 10.0	$ 1.1	$ 1.0
Interest Cost	14.7	17.9	3.5	4.4
Expected Return on Plan Assets	(24.9)	(27.5)	(8.8)	(8.5)
Amortization of Prior Service Credit	—	—	(7.1)	(7.1)
Amortization of Net Actuarial Loss	8.1	4.9	0.5	2.0
Net Periodic Benefit Cost (Credit)	$ 9.5	$ 5.3	$ (10.8)	$ (8.2)

OPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 2.4	$ 1.9	$ 0.2	$ 0.2
Interest Cost	3.9	4.8	1.0	1.4
Expected Return on Plan Assets	(6.6)	(7.3)	(2.6)	(2.7)
Amortization of Prior Service Credit	—	—	(1.8)	(1.8)
Amortization of Net Actuarial Loss	2.1	1.3	0.2	0.6
Net Periodic Benefit Cost (Credit)	$ 1.8	$ 0.7	$ (3.0)	$ (2.3)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 7.2	$ 5.9	$ 0.7	$ 0.6
Interest Cost	11.6	14.3	3.1	4.1
Expected Return on Plan Assets	(19.7)	(22.0)	(7.9)	(8.1)
Amortization of Prior Service Credit	—	—	(5.3)	(5.2)
Amortization of Net Actuarial Loss	6.4	4.0	0.5	1.9
Net Periodic Benefit Cost (Credit)	$ 5.5	$ 2.2	$ (8.9)	$ (6.7)

PSO

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 1.9	$ 1.6	$ 0.1	$ 0.2
Interest Cost	2.1	2.6	0.6	0.7
Expected Return on Plan Assets	(3.6)	(4.0)	(1.3)	(1.3)
Amortization of Prior Service Credit	—	—	(1.0)	(1.1)
Amortization of Net Actuarial Loss	1.1	0.7	—	0.3
Net Periodic Benefit Cost (Credit)	$ 1.5	$ 0.9	$ (1.6)	$ (1.2)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 5.5	$ 4.9	$ 0.4	$ 0.5
Interest Cost	6.4	7.9	1.6	2.0
Expected Return on Plan Assets	(10.9)	(12.2)	(3.9)	(3.9)
Amortization of Prior Service Credit	—	—	(3.2)	(3.2)
Amortization of Net Actuarial Loss	3.5	2.2	0.2	0.9
Net Periodic Benefit Cost (Credit)	$ 4.5	$ 2.8	$ (4.9)	$ (3.7)

SWEPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 2.6	$ 2.1	$ 0.2	$ 0.2
Interest Cost	2.5	3.1	0.6	0.7
Expected Return on Plan Assets	(3.9)	(4.4)	(1.5)	(1.5)
Amortization of Prior Service Credit	—	—	(1.3)	(1.3)
Amortization of Net Actuarial Loss	1.4	0.9	0.1	0.4
Net Periodic Benefit Cost (Credit)	$ 2.6	$ 1.7	$ (1.9)	$ (1.5)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Service Cost	$ 7.5	$ 6.4	$ 0.6	$ 0.6
Interest Cost	7.6	9.3	1.9	2.3
Expected Return on Plan Assets	(11.7)	(13.3)	(4.7)	(4.5)
Amortization of Prior Service Credit	—	—	(3.9)	(3.9)
Amortization of Net Actuarial Loss	4.2	2.6	0.3	1.1
Net Periodic Benefit Cost (Credit)	$ 7.6	$ 5.0	$ (5.8)	$ (4.4)

Qualified Pension Contribution (Applies to all Registrants except AEPTCo and PSO)

For the qualified pension plan, discretionary contributions may be made to maintain the funded status of the plan. In the third quarter of 2020, AEP made a discretionary contribution to the qualified pension plan. The following table provides details of the contribution by Registrant:

Company	Qualified Pension Plan	
	(in millions)	
AEP	$	110.3
AEP Texas		11.3
APCo		7.0
I&M		6.4
OPCo		0.1
SWEPCo		8.9

8. BUSINESS SEGMENTS

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

AEP's Reportable Segments

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo.
- OPCo purchases energy and capacity to serve standard service offer customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

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

Generation & Marketing

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

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

The tables below present AEP's reportable segment income statement information for the three and nine months ended September 30, 2020 and 2019 and reportable segment balance sheet information as of September 30, 2020 and December 31, 2019.

	Three Months Ended September 30, 2020						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 2,400.1	$ 1,124.1	$ 73.4	$ 464.8	$ 4.0	$ —	$ 4,066.4
Other Operating Segments	34.7	41.2	244.5	25.2	28.6	(374.2)	—
Total Revenues	$ 2,434.8	$ 1,165.3	$ 317.9	$ 490.0	$ 32.6	$ (374.2)	$ 4,066.4
Net Income (Loss)	$ 394.2	$ 147.4	$ 139.3	$ 114.6	$ (47.3)	$ —	$ 748.2

	Three Months Ended September 30, 2019						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 2,598.9	$ 1,147.3	$ 65.5	$ 501.2	$ 2.1	$ —	$ 4,315.0
Other Operating Segments	46.6	39.3	207.5	32.5	22.3	(348.2)	—
Total Revenues	$ 2,645.5	$ 1,186.6	$ 273.0	$ 533.7	$ 24.4	$ (348.2)	$ 4,315.0
Net Income (Loss)	$ 438.4	$ 133.7	$ 127.0	$ 88.7	$ (53.9)	$ —	$ 733.9

	Nine Months Ended September 30, 2020						
	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	$ 6,655.4	$ 3,208.7	$ 215.7	$ 1,223.4	$ 4.7	$ —	$ 11,307.9
Other Operating Segments	98.1	98.0	662.1	82.1	67.3	(1,007.6)	—
Total Revenues	$ 6,753.5	$ 3,306.7	$ 877.8	$ 1,305.5	$ 72.0	$ (1,007.6)	$ 11,307.9
Net Income (Loss)	$ 896.8	$ 403.1	$ 373.1	$ 203.6	$ (114.6)	$ —	$ 1,762.0

	Nine Months Ended September 30, 2019						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 7,087.6	$ 3,328.7	$ 196.5	$ 1,323.8	$ 8.8	$ —	$ 11,945.4
Other Operating Segments	85.0	125.6	611.8	104.4	64.9	(991.7)	—
Total Revenues	$ 7,172.6	$ 3,454.3	$ 808.3	$ 1,428.2	$ 73.7	$ (991.7)	$ 11,945.4
Net Income (Loss)	$ 920.8	$ 421.6	$ 407.6	$ 133.1	$ (116.0)	$ —	$ 1,767.1

	September 30, 2020						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$ 48,533.5	$ 20,738.7	$ 11,377.1	$ 1,854.4	$ 399.3	$ —	$ 82,903.0
Accumulated Depreciation and Amortization	15,340.1	3,891.6	553.1	150.1	181.7	—	20,116.6
Total Property Plant and Equipment - Net	$ 33,193.4	$ 16,847.1	$ 10,824.0	$ 1,704.3	$ 217.6	$ —	$ 62,786.4
Total Assets	$ 42,110.4	$ 19,250.3	$ 12,035.8	$ 3,368.6	$ 5,718.9 (b)	$ (3,794.7) (c)	$ 78,689.3
Long-term Debt Due Within One Year:							
Nonaffiliated	1,313.7	87.8	2.3	—	507.8 (d)	—	1,911.6
Long-term Debt:							
Affiliated	59.0	—	—	—	—	(59.0)	—
Nonaffiliated	12,048.7	7,196.7	4,123.2	—	4,786.9 (d)	—	28,155.5
Total Long-term Debt	$ 13,421.4	$ 7,284.5	$ 4,125.5	$ —	$ 5,294.7	$ (59.0)	$ 30,067.1

	December 31, 2019						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Property, Plant and Equipment	$ 47,323.7	$ 19,773.3	$ 10,334.0	$ 1,650.8	$ 418.4	$ (354.5) (e)	$ 79,145.7
Accumulated Depreciation and Amortization	14,580.4	3,911.2	418.9	99.0	184.5	(186.4) (e)	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) (e)	$ 60,138.1
Total Assets	$ 41,228.8	$ 18,757.5	$ 11,143.5	$ 3,123.8	$ 5,440.0 (b)	$ (3,801.3) (c) (e)	$ 75,892.3
Long-term Debt Due Within One Year:							
Affiliated	$ 20.0	$ —	$ —	$ —	$ —	$ (20.0)	$ —
Nonaffiliated	704.7	392.2	—	—	501.8 (d)	—	1,598.7
Long-term Debt:							
Affiliated	39.0	—	—	—	—	(39.0)	—
Nonaffiliated	12,162.0	6,248.1	3,593.8	—	3,122.9 (d)	—	25,126.8
Total Long-term Debt	$ 12,925.7	$ 6,640.3	$ 3,593.8	$ —	$ 3,624.7	$ (59.0)	$ 26,725.5

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

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

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

AEPTCo's Reportable Segments

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

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

The tables below present AEPTCo's reportable segment income statement information for the three and nine months ended September 30, 2020 and 2019 and reportable segment balance sheet information as of September 30, 2020 and December 31, 2019.

	Three Months Ended September 30, 2020			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Revenues from:				
External Customers	$ 62.9	$ —	$ —	$ 62.9
Sales to AEP Affiliates	241.2	—	—	241.2
Total Revenues	$ 304.1	$ —	$ —	$ 304.1
Interest Income	$ —	$ 38.4	$ (38.2) (a)	$ 0.2
Interest Expense	32.7	38.2	(38.2) (a)	32.7
Income Tax Expense	31.7	—	—	31.7
Net Income	$ 117.5	$ 0.1 (b)	$ —	$ 117.6

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

	Nine Months Ended September 30, 2020			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 184.6	$ —	$ —	$ 184.6
Sales to AEP Affiliates	652.6	—	—	652.6
Other Revenues	0.6	—	—	0.6
Total Revenues	$ 837.8	$ —	$ —	$ 837.8
Interest Income	$ 0.9	$ 111.3	$ (109.9) (a)	$ 2.3
Interest Expense	95.1	109.9	(109.9) (a)	95.1
Income Tax Expense	82.7	0.1	—	82.8
Net Income	$ 308.0	$ 1.1 (b)	$ —	$ 309.1

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

	September 30, 2020			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Transmission Property	$ 10,921.3	$ —	$ —	$ 10,921.3
Accumulated Depreciation and Amortization	531.8	—	—	531.8
Total Transmission Property – Net	$ 10,389.5	$ —	$ —	$ 10,389.5
Notes Receivable - Affiliated	$ —	$ 3,947.9	$ (3,947.9) (c)	$ —
Total Assets	$ 10,641.8	$ 4,104.1 (d)	$ (4,047.2) (e)	$ 10,698.7
Total Long-term Debt	$ 3,990.0	$ 3,947.9	$ (3,990.0) (c)	$ 3,947.9

	December 31, 2019			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
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

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

9. DERIVATIVES AND HEDGING

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 SubsidiariesAEPEP 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
September 30, 2020

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	390.6	—	71.7	28.9	3.1	19.8	5.6
Natural Gas	MMBtus	33.3	—	—	—	—	—	8.8
Heating Oil and Gasoline	Gallons	8.3	2.2	1.3	0.8	1.7	0.9	1.1
Interest Rate	USD	$ 129.8	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 200.0	$ —	$ 200.0	$ —	$ —	$ —	$ —

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	$ —	$ —	$ —	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

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

Cash Flow Hedging Strategies

The Registrants utilize cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. The Registrants do not hedge all commodity price risk.

The Registrants utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. The Registrants also utilize interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The Registrants do not hedge all interest rate exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrants apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third-party contractual agreements and risk profiles. AEP netted cash collateral received from third-parties against short-term and long-term risk management assets in the amounts of $0 and $5 million as of September 30, 2020 and December 31, 2019, respectively. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $9 million and $39 million as of September 30, 2020 and December 31, 2019, 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 Registrant Subsidiaries as of September 30, 2020 and December 31, 2019.

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

AEP

Fair Value of Derivative Instruments
September 30, 2020

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	$ 253.7	$ 24.5	$ 0.6	$ 278.8	$ (163.6)	$ 115.2
Long-term Risk Management Assets	283.3	17.5	—	300.8	(57.9)	242.9
Total Assets	537.0	42.0	0.6	579.6	(221.5)	358.1
Current Risk Management Liabilities	183.1	40.6	5.3	229.0	(166.6)	62.4
Long-term Risk Management Liabilities	239.0	57.0	—	296.0	(63.6)	232.4
Total Liabilities	422.1	97.6	5.3	525.0	(230.2)	294.8
Total MTM Derivative Contract Net Assets (Liabilities)	$ 114.9	$ (55.6)	$ (4.7)	$ 54.6	$ 8.7	$ 63.3

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

AEP Texas

Fair Value of Derivative Instruments
September 30, 2020

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	0.2	(0.1)	0.1
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.2	(0.1)	0.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ (0.2)	$ 0.1	$ (0.1)

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	$ —	$ —	$ —

APCo

Fair Value of Derivative Instruments
September 30, 2020

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Hedging Contracts – Interest Rate (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	$ 49.6	$ 0.6	$ (19.5)	$ 30.7
Long-term Risk Management Assets	1.6	—	(1.5)	0.1
Total Assets	51.2	0.6	(21.0)	30.8
Current Risk Management Liabilities	20.7	5.3	(20.4)	5.6
Long-term Risk Management Liabilities	1.8	—	(1.6)	0.2
Total Liabilities	22.5	5.3	(22.0)	5.8
Total MTM Derivative Contract Net Assets (Liabilities)	$ 28.7	$ (4.7)	$ 1.0	$ 25.0

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

I&M

Fair Value of Derivative Instruments
September 30, 2020

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	$ 16.5	$ (12.4)	$ 4.1
Long-term Risk Management Assets	1.0	(1.0)	—
Total Assets	17.5	(13.4)	4.1
Current Risk Management Liabilities	13.1	(12.9)	0.2
Long-term Risk Management Liabilities	1.1	(1.0)	0.1
Total Liabilities	14.2	(13.9)	0.3
Total MTM Derivative Contract Net Assets	$ 3.3	$ 0.5	$ 3.8

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

OPCo

Fair Value of Derivative Instruments
September 30, 2020

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	8.3	(0.1)	8.2
Long-term Risk Management Liabilities	105.1	—	105.1
Total Liabilities	113.4	(0.1)	113.3
Total MTM Derivative Contract Net Assets (Liabilities)	$ (113.4)	$ 0.1	$ (113.3)

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)

PSO

Fair Value of Derivative Instruments
September 30, 2020

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	$ 16.6	$ —	$ 16.6
Long-term Risk Management Assets	—	—	—
Total Assets	16.6	—	16.6
Current Risk Management Liabilities	0.6	(0.1)	0.5
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.6	(0.1)	0.5
Total MTM Derivative Contract Net Assets	$ 16.0	$ 0.1	$ 16.1

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

SWEPCo

Fair Value of Derivative Instruments
September 30, 2020

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	$ 4.5	$ —	$ 4.5
Long-term Risk Management Assets	—	—	—
Total Assets	4.5	—	4.5
Current Risk Management Liabilities	0.2	(0.1)	0.1
Long-term Risk Management Liabilities	0.7	—	0.7
Total Liabilities	0.9	(0.1)	0.8
Total MTM Derivative Contract Net Assets	$ 3.6	$ 0.1	$ 3.7

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

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

The tables below present the Registrants' activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts
Three Months Ended September 30, 2020

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 0.5	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	11.5	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.3	—	—	—	—
Purchased Electricity for Resale	0.3	—	0.2	0.1	—	—	—
Other Operation	(0.4)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Maintenance	(0.8)	(0.2)	(0.1)	(0.1)	(0.2)	—	(0.1)
Regulatory Assets (a)	7.9	0.2	0.4	0.2	4.4	(0.4)	2.9
Regulatory Liabilities (a)	17.0	—	3.8	2.6	1.7	3.1	2.0
Total Gain (Loss) on Risk Management Contracts	$ 36.0	$ (0.1)	$ 4.5	$ 2.7	$ 5.8	$ 2.6	$ 4.7

Three Months Ended September 30, 2019

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

Nine Months Ended September 30, 2020

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 0.8	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	11.1	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.4	0.1	—	—	0.1
Purchased Electricity for Resale	1.2	—	1.0	0.1	—	—	—
Other Operation	(1.4)	(0.4)	(0.2)	(0.2)	(0.3)	(0.2)	(0.2)
Maintenance	(2.2)	(0.6)	(0.3)	(0.2)	(0.4)	(0.2)	(0.3)
Regulatory Assets (a)	(8.5)	(0.3)	(0.1)	(0.2)	(9.9)	(0.6)	2.2
Regulatory Liabilities (a)	80.9	—	16.2	8.8	8.4	23.9	14.8
Total Gain (Loss) on Risk Management Contracts	$ 81.9	$ (1.3)	$ 17.0	$ 8.4	$ (2.2)	$ 22.9	$ 16.6

Nine Months Ended September 30, 2019

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

(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 Liabilities		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Liabilities	
	September 30, 2020	December 31, 2019	September 30, 2020	December 31, 2019
	(in millions)			
Long-term Debt (a) (b)	$ (551.9)	$ (510.8)	$ (55.2)	$ (14.5)

(a) Amounts included on the balance sheets within Long-term Debt Due within One Year and Long-term Debt, respectively.
(b) Amounts include $(55) million and $0 as of September 30, 2020 and December 31, 2019, respectively, for the fair value hedge adjustment of hedged debt obligations for which hedge accounting has been discontinued.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Gain (Loss) on Interest Rate Contracts:				
Gain on Fair Value Hedging Instruments (a)	$ —	$ 13.2	$ 42.6	$ 42.5
Loss on Fair Value Portion of Long-term Debt (a)	—	(13.2)	(42.6)	(42.5)

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

In June 2020, AEP terminated a $500 million notional amount interest rate swap resulting in the discontinuance of the hedging relationship. A gain of $57 million on the fair value of the hedging instrument was settled in cash and recorded within operating activities on the statement of cash flows. Subsequent to the discontinuation of hedge accounting, the remaining adjustment to the carrying amount of the hedged item of $57 million will be amortized on a straight line basis through November 2027 in Interest Expense on the statements of income.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects net income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2020 and 2019, AEP applied cash flow hedging to outstanding power derivatives. During the three and nine months ended September 30, 2020 and 2019, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2020, AEP and APCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the three and nine months ended September 30, 2019, AEP applied cash flow hedging to outstanding interest rate derivatives and the Registrant Subsidiaries did not.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges, see Note 3 - Comprehensive Income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets were:

Impact of Cash Flow Hedges on AEP's Balance Sheets

	September 30, 2020		December 31, 2019	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ (45.1)	$ (52.3)	$ (103.5)	$ (11.5)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	(13.9)	(5.3)	(51.7)	(2.1)

As of September 30, 2020 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 126 months and 123 months for commodity and interest rate hedges, respectively.

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

	September 30, 2020		December 31, 2019	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ (2.6)	$ (1.1)	$ (3.4)	$ (1.1)
APCo	(3.5)	0.6	0.9	0.9
I&M	(8.7)	(1.6)	(9.9)	(1.6)
PSO	0.3	0.3	1.1	1.0
SWEPCo	(0.7)	(1.5)	(1.8)	(1.5)

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

Management mitigates credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Collateral Triggering Events

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

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. The Registrants have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. The Registrants had no derivative contracts with collateral triggering events in a net liability position as of September 30, 2020 and December 31, 2019, respectively.

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

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following tables represent: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount that the exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	September 30, 2020		
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	$ 189.7	$ —	$ 162.3
APCo	5.7	—	5.3
I&M	0.3	—	—
SWEPCo	0.9	—	0.9

	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

10. FAIR VALUE MEASUREMENTS

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

Fair Value Hierarchy and Valuation Techniques

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

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

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

Assets in the nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

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

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value of AEP's Equity Units (Level 1) are valued based on publicly traded securities issued by AEP.

The book values and fair values of Long-term Debt are summarized in the following table:

	September 30, 2020		December 31, 2019	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in millions)			
AEP (a)	$ 30,067.1	$ 35,603.2	$ 26,725.5	$ 30,172.0
AEP Texas	4,854.7	5,590.0	4,558.4	4,981.5
AEPTCo	3,947.9	4,859.5	3,427.3	3,868.0
APCo	4,833.3	6,167.6	4,363.8	5,253.1
I&M	2,981.9	3,637.4	3,050.2	3,453.8
OPCo	2,429.9	3,137.5	2,082.0	2,554.3
PSO	1,373.7	1,694.9	1,386.2	1,603.3
SWEPCo	2,637.3	3,119.2	2,655.6	2,927.9

(a) The fair value amounts include debt related to AEP's Equity Units and had a fair value of $1.6 billion and $871 million as of September 30, 2020 and December 31, 2019, respectively. See "Equity Units" section of Note 12 for additional information.

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS.

The following is a summary of Other Temporary Investments:

	September 30, 2020			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$ 79.6	$ —	$ —	$ 79.6
Fixed Income Securities – Mutual Funds (b)	127.9	2.9	—	130.8
Equity Securities – Mutual Funds	30.2	22.5	—	52.7
Total Other Temporary Investments	$ 237.7	$ 25.4	$ —	$ 263.1

	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

(a) Primarily represents amounts held for the repayment of debt.
(b) Primarily short and intermediate maturities which may be sold and do not contain maturity dates.

The following table provides the activity for fixed income and equity securities within Other Temporary Investments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Proceeds from Investment Sales	$ 5.1	$ 2.8	$ 35.9	$ 2.8
Purchases of Investments	22.5	26.9	39.5	35.8
Gross Realized Gains on Investment Sales	0.2	—	2.4	—
Gross Realized Losses on Investment Sales	—	—	0.2	—

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

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

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

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

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Available-for-sale classification only applies to investment in debt securities in accordance with ASU 2016-01. Additionally, ASU 2016-01 requires changes in fair value of equity securities to be recognized in earnings. However, due to the regulatory treatment described below, this is not applicable for I&M's trust fund securities.

Other-than-temporary impairments for investments in debt securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains, unrealized losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI.

The following is a summary of nuclear trust fund investments:

	September 30, 2020			December 31, 2019		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 33.7	$ —	$ —	$ 15.3	$ —	$ —
Fixed Income Securities:						
United States Government	1,039.2	112.3	(5.8)	1,112.5	55.5	(6.1)
Corporate Debt	85.6	8.9	(1.5)	72.4	5.3	(1.6)
State and Local Government	123.9	1.5	(0.3)	7.6	0.7	(0.2)
Subtotal Fixed Income Securities	1,248.7	122.7	(7.6)	1,192.5	61.5	(7.9)
Equity Securities - Domestic (a)	1,793.5	1,165.8	—	1,767.9	1,144.4	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 3,075.9	$ 1,288.5	$ (7.6)	$ 2,975.7	$ 1,205.9	$ (7.9)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $1.2 billion and $1.1 billion and unrealized losses of $17 million and $5 million as of September 30, 2020 and December 31, 2019, respectively.

The following table provides the securities activity within the decommissioning and SNF trusts:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(in millions)			
Proceeds from Investment Sales	$ 316.6	$ 671.9	$ 1,257.1	$ 871.4
Purchases of Investments	318.6	689.1	1,290.0	915.7
Gross Realized Gains on Investment Sales	3.4	10.9	25.4	26.6
Gross Realized Losses on Investment Sales	0.5	7.1	25.2	15.1

The base cost of fixed income securities was $1.1 billion and $1.1 billion as of September 30, 2020 and December 31, 2019, respectively. The base cost of equity securities was $628 million and $623 million as of September 30, 2020 and December 31, 2019, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2020 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 291.6
After 1 year through 5 years	355.9
After 5 years through 10 years	255.1
After 10 years	346.1
Total	$ 1,248.7

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 66.3	$ —	$ —	$ 13.3	$ 79.6
Fixed Income Securities – Mutual Funds	130.8	—	—	—	130.8
Equity Securities – Mutual Funds (b)	52.7	—	—	—	52.7
Total Other Temporary Investments	249.8	—	—	13.3	263.1
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	3.2	247.1	280.3	(185.3)	345.3
Cash Flow Hedges:					
Commodity Hedges (c)	—	36.1	4.3	(28.2)	12.2
Interest Rate Hedges	—	0.6	—	—	0.6
Total Risk Management Assets	3.2	283.8	284.6	(213.5)	358.1
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	24.7	—	—	9.0	33.7
Fixed Income Securities:					
United States Government	—	1,039.2	—	—	1,039.2
Corporate Debt	—	85.6	—	—	85.6
State and Local Government	—	123.9	—	—	123.9
Subtotal Fixed Income Securities	—	1,248.7	—	—	1,248.7
Equity Securities – Domestic (b)	1,793.5	—	—	—	1,793.5
Total Spent Nuclear Fuel and Decommissioning Trusts	1,818.2	1,248.7	—	9.0	3,075.9
Total Assets	$ 2,071.2	$ 1,532.5	$ 284.6	$ (191.2)	$ 3,697.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 3.4	$ 239.1	$ 173.2	$ (194.0)	$ 221.7
Cash Flow Hedges:					
Commodity Hedges (c)	—	90.7	5.3	(28.2)	67.8
Interest Rate Hedges	—	5.3	—	—	5.3
Total Risk Management Liabilities	$ 3.4	$ 335.1	$ 178.5	$ (222.2)	$ 294.8

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) (f)	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) (f)	$ 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 Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 44.8	$ —	$ —	$ —	$ 44.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.2	$ —	$ (0.1)	$ 0.1

December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 154.7	$ —	$ —	$ —	$ 154.7

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 9.3	$ —	$ —	$ —	$ 9.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	20.4	30.1	(20.3)	30.2
Cash Flow Hedges:					
Interest Rate Hedges	—	0.6	—	—	0.6
Total Risk Management Assets	—	21.0	30.1	(20.3)	30.8
Total Assets	$ 9.3	$ 21.0	$ 30.1	$ (20.3)	$ 40.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 21.2	$ 0.5	$ (21.2)	$ 0.5
Cash Flow Hedges:					
Interest Rate Hedges	—	5.3	—	—	5.3
Total Risk Management Liabilities	$ —	$ 26.5	$ 0.5	$ (21.2)	$ 5.8

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

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 12.9	$ 4.1	$ (12.9)	$ 4.1
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	24.7	—	—	9.0	33.7
Fixed Income Securities:					
United States Government	—	1,039.2	—	—	1,039.2
Corporate Debt	—	85.6	—	—	85.6
State and Local Government	—	123.9	—	—	123.9
Subtotal Fixed Income Securities	—	1,248.7	—	—	1,248.7
Equity Securities - Domestic (b)	1,793.5	—	—	—	1,793.5
Total Spent Nuclear Fuel and Decommissioning Trusts	1,818.2	1,248.7	—	9.0	3,075.9
Total Assets	$ 1,818.2	$ 1,261.6	$ 4.1	$ (3.9)	$ 3,080.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 13.4	$ 0.3	$ (13.4)	$ 0.3

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

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2020

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 113.2	$ (0.1)	$ 113.3

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

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 16.6	$ —	$ 16.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.1	$ 0.5	$ (0.1)	$ 0.5

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)	$ —

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2020

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 4.4	$ 0.1	$ 4.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.1	$ 0.7	$ —	$ 0.8

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

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or third-parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

(d) The September 30, 2020 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 2 matures $(6) million in 2020, $3 million in periods 2021-2023, $4 million in periods 2024-2025 and $7 million in periods 2026-2033; Level 3 matures $35 million in 2020, $63 million in periods 2021-2023, $21 million in periods 2024-2025 and $(12) million in periods 2026-2033. 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, 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.

(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:

Three Months Ended September 30, 2020	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2020	$ 111.6	$ 36.5	$ 4.5	$ (117.4)	$ 23.8	$ 3.3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	18.7	6.4	3.3	—	3.0	1.5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	6.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	2.6	—	—	—	—	—
Settlements	(37.0)	(11.1)	(5.0)	1.3	(10.3)	(3.5)
Transfers into Level 3 (d) (e)	(1.0)	—	—	—	—	—
Transfers out of Level 3 (e)	1.1	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	3.6	(2.2)	1.0	2.9	(0.4)	2.4
Balance as of September 30, 2020	$ 106.1	$ 29.6	$ 3.8	$ (113.2)	$ 16.1	$ 3.7

Three Months Ended September 30, 2019	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of June 30, 2019	$ 112.7	$ 68.5	$ 12.3	$ (111.5)	$ 27.8	$ 8.5
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	30.2	13.8	3.1	—	4.1	3.6
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	2.9	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	22.1	—	—	—	—	—
Settlements	(67.4)	(28.1)	(7.2)	1.1	(11.2)	(6.7)
Transfers into Level 3 (d) (e)	3.5	—	—	—	—	—
Transfers out of Level 3 (e)	6.6	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(0.3)	1.3	0.7	(2.1)	0.9	(0.5)
Balance as of September 30, 2019	$ 110.3	$ 55.5	$ 8.9	$ (112.5)	$ 21.6	$ 4.9

Nine Months Ended September 30, 2020	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of December 31, 2019	$ 109.9	$ 37.7	$ 5.8	$ (103.6)	$ 15.8	$ 1.4
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	39.6	13.1	2.4	(1.2)	11.9	2.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(2.4)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	21.7	—	—	—	—	—
Settlements	(115.3)	(51.4)	(8.5)	6.4	(27.6)	(6.9)
Transfers into Level 3 (d) (e)	(1.1)	—	—	—	—	—
Transfers out of Level 3 (e)	5.6	0.7	0.4	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	48.1	29.5	3.7	(14.8)	16.0	6.4
Balance as of September 30, 2020	$ 106.1	$ 29.6	$ 3.8	$ (113.2)	$ 16.1	$ 3.7

Nine Months Ended September 30, 2019	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2018	$ 131.2	$ 57.8	$ 8.9	$ (99.4)	$ 9.5	$ 2.3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	14.6	(14.1)	4.6	(0.9)	13.5	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	32.9	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(42.8)	—	—	—	—	—
Settlements	(114.6)	(41.9)	(12.6)	4.6	(23.0)	(10.1)
Transfers into Level 3 (d) (e)	0.4	—	—	—	—	—
Transfers out of Level 3 (e)	1.4	(0.7)	(0.4)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	87.2	54.4	8.4	(16.8)	21.6	6.7
Balance as of September 30, 2019	$ 110.3	$ 55.5	$ 8.9	$ (112.5)	$ 21.6	$ 4.9

(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:

AEP

Significant Unobservable Inputs
September 30, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 219.2	$ 173.0	Discounted Cash Flow	Forward Market Price (a)	$ 3.36	$ 111.42	$ 32.62
Natural Gas Contracts	—	0.6	Discounted Cash Flow	Forward Market Price (b)	1.79	3.06	2.61
FTRs	65.4	4.9	Discounted Cash Flow	Forward Market Price (a)	(6.15)	10.66	0.23
Total	$ 284.6	$ 178.5					

December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	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					

APCo

Significant Unobservable Inputs
September 30, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 0.8	$ 0.5	Discounted Cash Flow	Forward Market Price	$ 9.56	$ 41.80	$ 27.25
FTRs	29.3	—	Discounted Cash Flow	Forward Market Price	(0.81)	6.57	1.09
Total	$ 30.1	$ 0.5					

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					

I&M

Significant Unobservable Inputs
September 30, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 0.5	$ 0.3	Discounted Cash Flow	Forward Market Price	$ 9.56	$ 41.80	$ 27.25
FTRs	3.6	—	Discounted Cash Flow	Forward Market Price	(2.68)	4.24	0.41
Total	$ 4.1	$ 0.3					

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					

OPCo

Significant Unobservable Inputs
September 30, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 113.2	Discounted Cash Flow	Forward Market Price	$ 11.68	$ 47.28	$ 28.31

December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	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

PSO

Significant Unobservable Inputs
September 30, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 16.6	$ 0.5	Discounted Cash Flow	Forward Market Price	$ (5.98)	$ 0.70	$ (1.85)

December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	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)

SWEPCo

Significant Unobservable Inputs
September 30, 2020

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Input/Range Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ —	$ 0.6	Discounted Cash Flow	Forward Market Price (b)	$ 1.79	$ 3.02	$ 2.54
FTRs	4.4	0.1	Discounted Cash Flow	Forward Market Price (a)	(5.98)	0.70	(1.85)
Total	$ 4.4	$ 0.7					

December 31, 2019

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Input/Range 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					

(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 September 30, 2020 and December 31, 2019:

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)

11. INCOME TAXES

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

Federal Legislation

In March 2020, the CARES Act was signed into law. The CARES Act includes tax relief provisions such as: (a) an Alternative Minimum Ta (AMT) Credit Refund, (b) a 5-year net operating losses (NOL) carryback from years 2018-2020 and (c) delayed payment of employer payroll taxes. In May 2020, the House passed the "Health and Economic Recovery Omnibus Emergency Solutions Act" (HEROES Act) pending decision by th Senate. If enacted, the HEROES Act would disallow NOL carrybacks to any tax year beginning before January 1, 2018. Pursuant to the CARE Act, AEP, APCo and OPCo requested and in July received a $20 million, $7 million and $9 million, respectively, refund of AMT credit. In the third quarter of 2020, AEP also requested a $95 million refund of taxes paid in 2014 under the 5-year NOL carryback provision of the CARES ActAEP carried back an NOL generated on the 2019 Federal income tax return at a 21% federal corporate income tax rate to the 2014 Federal income tax return at a 35% corporate income tax rate. As a result of the change in the corporate income tax rates between the two periods, AEP realized a tax benefit of $52 million, recorded discretely, primarily at the Generation & Marketing segment. On October 1, 2020, after AEP filed its request with the IRS, the House passed a revised version of the HEROES Act; which similar to the original legislation would disallow NOL carryback to years prior t 2018. Management will continue to monitor the potential impact of this legislation. The Registrants are currently deferring payments of the employer share of payroll taxes for the period March 27, 2020 through December 31, 2020 and will pay 50% of the obligation by December 31, 2021 and the remaining 50% by December 31, 2022.

Effective Tax Rates (ETR)

The Registrants' interim ETR reflect the estimated annual ETR for 2020 and 2019, adjusted for tax expense associated with certain discrete items.

The Registrants include the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, the Registrants recognize the tax benefit discretely in the period recorded. The annual amount of Excess ADIT approved by the Registrant's regulatory commissions may not impact the ETR ratably during each interim period due to the variability of pretax book income between interim periods and the application of an annual estimated ETR.

The ETR for each of the Registrants are included in the following tables:

	Three Months Ended September 30, 2020							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	2.7 %	2.0 %	2.9 %	3.1 %	3.4 %	0.8 %	4.6 %	2.4 %
Tax Reform Excess ADIT Reversal	(11.0)%	(14.6)%	0.4 %	(22.0)%	(16.7)%	(6.7)%	(20.3)%	(7.3) %
Production and Investment Tax Credits	(4.6)%	(0.5)%	— %	— %	(1.6)%	— %	(1.1)%	(0.5) %
Flow Through	0.5 %	0.2 %	0.5 %	1.6 %	0.2 %	0.9 %	0.2 %	(1.2) %
AFUDC Equity	(1.5)%	(3.5)%	(2.6) %	(1.1)%	(0.9)%	(0.9)%	(0.6)%	(0.3) %
Parent Company Loss Benefit	— %	— %	(0.9) %	(3.1)%	(3.7)%	(0.3)%	(1.7)%	(2.0) %
Discrete Tax Adjustments	(7.4)%	(3.6)%	(0.2) %	(6.6)%	2.3 %	8.4 %	(0.6)%	(0.6) %
Other	0.1 %	0.3 %	0.1 %	— %	— %	0.3 %	0.1 %	(0.6) %
Effective Income Tax Rate	(0.2)%	1.3 %	21.2 %	(7.1)%	4.0 %	23.5 %	1.6 %	10.9 %

	Three Months Ended September 30, 2019							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	2.6 %	1.4 %	3.1 %	3.0 %	(0.1)%	0.4 %	4.8 %	2.4 %
Tax Reform Excess ADIT Reversal	(11.9)%	(6.1)%	1.4 %	(26.6)%	(17.3)%	(6.9)%	(16.5)%	(19.5) %
Production and Investment Tax Credits	(3.7)%	(0.2)%	— %	— %	(2.0)%	— %	(1.4)%	(0.9) %
Flow Through	0.4 %	— %	0.1 %	3.8 %	(0.7)%	1.0 %	0.7 %	(0.5) %
AFUDC Equity	(1.5)%	(1.1)%	(2.6) %	(1.3)%	(1.7)%	(1.7)%	(0.3)%	(0.9) %
Parent Company Loss Benefit	— %	(0.1)%	(1.3) %	(1.1)%	(1.0)%	0.4 %	(1.8)%	(1.8) %
Discrete Tax Adjustments	(1.7)%	— %	(0.1) %	(2.4)%	(1.3)%	1.7 %	— %	— %
Other	— %	0.2 %	0.3 %	(0.3)%	0.4 %	(2.0)%	(0.1)%	(0.4) %
Effective Income Tax Rate	5.2 %	15.1 %	21.9 %	(3.9)%	(2.7)%	13.9 %	6.4 %	(0.6) %

	Nine Months Ended September 30, 2020							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	2.6 %	1.8 %	2.9 %	3.1 %	3.4 %	0.7 %	4.6 %	2.3 %
Tax Reform Excess ADIT Reversal	(12.1)%	(23.4)%	0.4 %	(20.8)%	(16.7)%	(8.8)%	(20.3)%	(11.5) %
Production and Investment Tax Credits	(4.5)%	(0.5)%	— %	— %	(1.6)%	— %	(1.1)%	(0.5) %
Flow Through	0.5 %	0.1 %	0.5 %	1.6 %	0.2 %	0.9 %	0.2 %	(1.2) %
AFUDC Equity	(1.5)%	(3.2)%	(2.6) %	(1.1)%	(0.9)%	(0.9)%	(0.6)%	(0.3) %
Parent Company Loss Benefit	— %	— %	(0.9) %	(3.1)%	(3.7)%	(0.3)%	(1.7)%	(1.9) %
Discrete Tax Adjustments	(3.0)%	(1.6)%	(0.1) %	(2.3)%	1.8 %	2.6 %	(0.4)%	(0.3) %
Other	0.2 %	0.4 %	(0.1) %	(0.1)%	(0.1)%	0.2 %	0.1 %	(0.4) %
Effective Income Tax Rate	3.2 %	(5.4)%	21.1 %	(1.7)%	3.4 %	15.4 %	1.8 %	7.2 %

	Nine Months Ended September 30, 2019							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	2.1 %	1.5 %	3.0 %	3.3 %	1.2 %	0.7 %	4.7 %	1.8 %
Tax Reform Excess ADIT Reversal	(16.7)%	(43.9)%	0.7 %	(40.2)%	(17.3)%	(7.4)%	(18.2)%	(18.7) %
Production and Investment Tax Credits	(3.6)%	(0.5)%	— %	— %	(2.0)%	— %	(1.5)%	(0.8) %
Flow Through	0.1 %	0.1 %	0.2 %	0.7 %	(1.8)%	0.7 %	0.6 %	(0.6) %
AFUDC Equity	(1.5)%	(1.3)%	(2.5) %	(1.1)%	(1.9)%	(1.0)%	(0.3)%	(0.9) %
Parent Company Loss Benefit	— %	(1.0)%	(1.1) %	(1.9)%	(1.5)%	(0.7)%	(1.8)%	(1.5) %
Discrete Tax Adjustments	— %	(1.3)%	(0.6) %	(0.8)%	0.2 %	0.5 %	— %	(0.2) %
Other	0.3 %	0.1 %	— %	(0.1)%	— %	0.4 %	0.1 %	(0.1) %
Effective Income Tax Rate	1.7 %	(25.3)%	20.7 %	(19.1)%	(2.1)%	14.2 %	4.6 %	— %

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 2015During the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 and 2015 federal returns. In the first quarter of 2020, the IRS notified AEP that it was beginning an examination of these amended returns, including the net operating loss carryback to 2015 that originated in the 2017 return. The IRS may examine only the amended items on the 2014 and 2015 federal returns.

12. FINANCING ACTIVITIES

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

Reverse Stock Split (Applies to SWEPCo)

In August 2020, SWEPCo executed a reverse stock split with each 2,048 shares of common stock issued and outstanding being combined into one share of common stock. The common stock of SWEPCo is wholly-owned by Parent.

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding, net of issuance costs and premiums or discounts:

Type of Debt	September 30, 2020	December 31, 2019
	(in millions)	
Senior Unsecured Notes	$ 24,125.4	$ 21,180.7
Pollution Control Bonds	1,936.1	1,998.8
Notes Payable	161.3	234.3
Securitization Bonds	751.6	1,025.1
Spent Nuclear Fuel Obligation (a)	281.1	279.8
Junior Subordinated Notes (b)	1,622.1	787.8
Other Long-term Debt	1,189.5	1,219.0
Total Long-term Debt Outstanding	30,067.1	26,725.5
Long-term Debt Due Within One Year	1,911.6	1,598.7
Long-term Debt	$ 28,155.5	$ 25,126.8

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for SNF disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $326 million and $323 million as of September 30, 2020 and December 31, 2019, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.
(b) See "Equity Units" section below for additional information.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2020 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		(in millions)	(%)	
AEP	Junior Subordinated Notes (b)	$ 850.0	1.30	2025
AEP	Senior Unsecured Notes	400.0	2.30	2030
AEP	Senior Unsecured Notes	400.0	3.25	2050
AEP Texas	Pollution Control Bonds	60.0	0.90	2023
AEP Texas	Senior Unsecured Notes	600.0	2.10	2030
AEPTCo	Senior Unsecured Notes	525.0	3.65	2050
APCo	Pollution Control Bonds	65.4	1.00	2025
APCo	Senior Unsecured Notes	500.0	3.70	2050
OPCo	Senior Unsecured Notes	350.0	2.60	2030
Non-Registrant:				
KPCo	Other Long-term Debt	125.0	Variable	2022
Transource Energy	Other Long-term Debt	4.4	Variable	2020
Transource Energy	Other Long-term Debt	7.1	Variable	2023
Transource Energy	Senior Unsecured Notes	150.0	2.75	2050
Total Issuances		$ 4,036.9		

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.
(b) See "Equity Units" section below for additional information.

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		**(in millions)**	**(%)**	
AEP Texas	Pollution Control Bonds	$ 50.6	4.45	2020
AEP Texas	Securitization Bonds	28.7	1.98	2020
AEP Texas	Securitization Bonds	202.6	5.31	2020
AEP Texas	Pollution Control Bonds	60.0	1.75	2020
AEP Texas	Securitization Bonds	0.2	2.85	2024
AEP Texas	Securitization Bonds	14.4	2.06	2025
APCo	Pollution Control Bonds	65.4	1.70	2020
APCo	Securitization Bonds	24.9	2.01	2023
I&M	Notes Payable	2.0	Variable	2020
I&M	Notes Payable	4.6	Variable	2021
I&M	Notes Payable	14.9	Variable	2022
I&M	Notes Payable	11.4	Variable	2022
I&M	Notes Payable	18.7	Variable	2023
I&M	Notes Payable	18.2	Variable	2024
I&M	Other Long-term Debt	1.3	6.00	2025
OPCo	Other Long-term Debt	0.1	1.15	2028
PSO	Pollution Control Bonds	12.7	4.45	2020
PSO	Other Long-term Debt	0.3	3.00	2027
SWEPCo	Other Long-term Debt	15.0	Variable	2020
SWEPCo	Other Long-term Debt	1.5	4.68	2028
SWEPCo	Notes Payable	3.2	4.58	2032
Non-Registrant:				
Transource Energy	Other Long-term Debt	148.6	Variable	2023
Transource Energy	Senior Unsecured Notes	1.2	2.75	2050
Total Retirements and Principal Payments		$ 700.5		

Long-term Debt Subsequent Events

In October 2020, I&M issued $70 million of Notes Payable related to DCC Fuel.

In October 2020, I&M retired $5 million of Notes Payable related to DCC Fuel.

Equity Units (Applies to AEP)

2020 Equity Units

In August 2020, AEP issued 17 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $850 million. Net proceeds from the issuance were approximately $833 million. The proceeds were used to support AEP's overall capital expenditure plans.

Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 1.30% Junior Subordinated Notes (notes) due in 2025 and a forward equity purchase contract which settles after three years in 2023. The notes are expected to be remarketed in 2023, 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 1.30% and a quarterly forward equity purchase contract payment of 4.825%.

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 $99.95: 0.5003 shares per contract.
- If the AEP common stock market price is less than $99.95 but greater than $83.29: 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 $83.29: 0.6003 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 $850 million of notes were recorded within Long-term Debt on the balance sheets.The present value of the purchase contract payments of $121 million were recorded in Deferred Credits and Other Noncurrent Liabilitieswith 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 2023. 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 10,205,100 shares (subject to an anti-dilution adjustment).

2019 Equity Units

In March 2019, AEP issued16.1 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 was0.9% of consolidated tangible net assets as of September 30, 2020. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreements.

Dividend Restrictions

Utility Subsidiaries’ Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP’s utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. The Federal Power Act also creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to AGR, APCo and I&M.

Certain AEP subsidiaries have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings.

Parent Restrictions (Applies to AEP)

The holders of AEP’s common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent’s income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

Corporate Borrowing Program - AEP System (Applies to Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of September 30, 2020 and December 31, 2019 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' activity and corresponding authorized borrowing limits for the nine months ended September 30, 2020 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings) from the Utility Money Pool as of September 30, 2020	Authorized Short-term Borrowing Limit	
				(in millions)			
AEP Texas	$ 320.4	$ 313.4	$ 154.7	$ 167.4	$ 141.3	$ 500.0	
AEPTCo	358.4	259.7	112.7	59.1	(84.3)	820.0	(a)
APCo	434.3	189.0	274.8	74.6	155.2	500.0	
I&M	218.6	13.4	115.3	13.3	(145.8)	500.0	
OPCo	353.9	32.8	158.3	25.2	(215.9)	500.0	
PSO	125.4	57.1	64.6	28.4	(77.8)	300.0	
SWEPCo	178.9	—	113.6	—	(71.8)	350.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above table does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in th Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of September 30, 2020 and December 31, 2019 are included in Advances to Affiliates on the subsidiaries' balance sheets. The Nonutility Money Pool participants' activity for the nine months ended September 30, 2020 is described in the following table:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of September 30, 2020
		(in millions)	
AEP Texas	$ 7.5	$ 7.1	$ 7.1
SWEPCo	2.1	2.1	2.1

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs.The amounts of outstanding loans to and borrowings from AEP as of September 30, 2020 and December 31, 2019 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets.AEPTCo's direct borrowing and lending activity with AEP and corresponding authorized borrowing limit for the nine months ended September 30, 2020 are described in the following table:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of September 30, 2020	Loans to AEP as of September 30, 2020	Authorized Short-term Borrowing Limit	
				(in millions)			
$ 1.4	$ 195.8	$ 1.3	$ 128.7	$ 1.2	$ 105.4	$ 50.0	(a)

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Nine Months Ended September 30,	
	2020	2019
Maximum Interest Rate	2.70 %	3.43 %
Minimum Interest Rate	0.33 %	1.83 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized for all Registrant Subsidiaries in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Nine Months Ended September 30,		Average Interest Rate for Funds Loaned to the Utility Money Pool for Nine Months Ended September 30,	
Company	2020	2019	2020	2019
AEP Texas	1.55 %	2.71 %	0.87 %	— %
AEPTCo	1.63 %	2.72 %	2.00 %	2.57 %
APCo	2.14 %	2.82 %	0.99 %	2.73 %
I&M	1.30 %	2.56 %	1.44 %	2.73 %
OPCo	1.32 %	2.80 %	2.06 %	2.68 %
PSO	1.24 %	2.85 %	1.95 %	2.48 %
SWEPCo	1.55 %	2.74 %	— %	2.47 %

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool are summarized in the following table:

	Nine Months Ended September 30, 2020			Nine Months Ended September 30, 2019		
Company	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	2.70 %	0.33 %	1.44 %	3.02 %	2.36 %	2.70 %
SWEPCo	2.70 %	0.33 %	1.44 %	3.02 %	2.36 %	2.70 %

AEPTCo's maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following table:

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
2020	2.70 %	0.50 %	2.70 %	0.50 %	1.45 %	1.40 %
2019	3.02 %	2.36 %	3.02 %	2.36 %	2.70 %	2.70 %

Short-term Debt (Applies to AEP, AEP Texas and SWEPCo)

Outstanding short-term debt was as follows:

		September 30, 2020		December 31, 2019	
Company	Type of Debt	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
		(dollars in millions)			
AEP	Securitized Debt for Receivables (b)	$ 703.0	1.05 %	$ 710.0	2.42 %
AEP	Commercial Paper	650.0	0.21 %	2,110.0	2.10 %
AEP	364-Day Term Loan	1,000.0	0.75 %	—	— %
AEP Texas	COVID-19 Electricity Relief Program Loan (c)	2.0	— %	—	— %
SWEPCo	Notes Payable	42.0	2.46 %	18.3	3.29 %
	Total Short-term Debt	$ 2,397.0		$ 2,838.3	

(a) Weighted-average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) Principal amount of loan shall not bear interest if paid in full by the maturity date. Unpaid principal after the maturity date will accrue interest of 2% per annum beginning the first day after the maturity date until all outstanding principal is paid.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement that provides a commitment of $750 million from bank conduits to purchase receivables and expires in September 2022. 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.

In May 2020, AEP Credit amended its receivables securitization agreement to increase the eligibility criteria related to aged receivable requirements for the participating affiliated utility subsidiaries in response to the COVID-19 pandemic.As of September 30, 2020, the affiliated utility subsidiaries are in compliance with all requirements under the agreement. To the extent that an affiliated utility subsidiary is deemed ineligible under the agreement, receivables would no longer be purchased by the bank conduits and the Registrants would need to rely on additional sources of funding for operation and working capital, which may adversely impact liquidity.

Accounts receivable information for AEP Credit was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	0.36 %	2.37 %	1.05 %	2.56 %
Net Uncollectible Accounts Receivable Written-Off	$ 2.9	$ 8.8	$ 10.5	$ 19.8

	September 30, 2020	December 31, 2019
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,002.4	$ 841.8
Short-term – Securitized Debt of Receivables	703.0	710.0
Delinquent Securitized Accounts Receivable	103.8	39.6
Bad Debt Reserves Related to Securitization	52.7	32.1
Unbilled Receivables Related to Securitization	227.4	266.8

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to Registrant Subsidiaries, except AEP Texas and AEPTCo)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit.AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreements were:

Company	September 30, 2020	December 31, 2019
	(in millions)	
APCo	$ 117.3	$ 120.9
I&M	184.3	141.8
OPCo	394.3	330.3
PSO	122.0	101.1
SWEPCo	177.6	125.2

The fees paid to AEP Credit for customer accounts receivable sold were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2020	2019	2020	2019
		(in millions)		
APCo	$ 2.0	$ 1.2	$ 5.0	$ 5.8
I&M	3.9	2.4	9.3	8.4
OPCo	9.8	6.4	19.6	22.1
PSO	1.5	2.0	3.8	6.2
SWEPCo	2.8	1.9	6.8	7.9

The proceeds on the sale of receivables to AEP Credit were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2020	2019	2020	2019
		(in millions)		
APCo	$ 323.5	$ 303.3	$ 961.8	$ 978.5
I&M	532.3	485.3	1,443.6	1,378.9
OPCo	666.0	602.6	1,793.0	1,746.1
PSO	369.2	451.5	961.4	1,118.7
SWEPCo	478.3	480.7	1,225.3	1,247.0

13. PROPERTY, PLANT AND EQUIPMENT

The disclosure in this note applies to AEP, AEP Texas, APCo, PSO and SWEPCo.

Asset Retirement Obligations

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. The Registrants recorded the following revisions to ARO estimates during the first nine months of 2020:

- In March 2020, SWEPCo recorded a revision to increase estimated ARO liabilities by $21 million primarily due to the revision in the useful life of DHLC. See Note 4 - Rate Matters for additional details. In September 2020, SWEPCo recorded an $8 million revision due to a reduction in estimated ash pond closure costs.
- In June 2020, AEP Texas and PSO recorded a revision to decrease estimated ARO liabilities by $17 million and $5 million, respectively, due to the retirement of the Oklaunion Power Station in September 2020. See Note 4 - Rate Matters for additional details.
- In June 2020, AGR derecognized $106 million of Conesville Plant related ARO liabilities as a result of the Environmental Liability and Property Transfer and Asset Purchase Agreement executed with a non-affiliated third-party. See Note 6 - Acquisitions and Dispositions for additional details.
- In June 2020, APCo recorded a revision to increase estimated Glen Lyn Station ash disposal ARO liabilities by $99 million due to the enactment of House Bill 443. This bill requires APCo to close the ash disposal units at the retired Glen Lyn Station by removal of all coal combustion material. The legislation provides for regulatory recovery of these costs. See Note 5 - Commitments, Guarantees and Contingencies for additional details.

The following is a reconciliation of the aggregate carrying amounts of ARO for AEP, AEP Texas, APCo, PSO and SWEPCo:

Company	ARO as of December 31, 2019	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of September 30, 2020
			(in millions)			
AEP (a)(b)(c)(d)	$ 2,418.9	$ 76.8	$ 0.2	$ (155.4)	$ 170.5	$ 2,511.0
AEP Texas (a)(d)	29.1	0.7	—	—	(16.8)	13.0
APCo (a)(d)	111.1	5.9	—	(5.3)	195.4	307.1
PSO (a)(d)	52.2	2.3	—	(0.5)	(4.8)	49.2
SWEPCo (a)(c)(d)	212.2	8.2	—	(5.6)	6.2	221.0

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.78 billion and $1.73 billion as of September 30, 2020 and December 31, 2019, respectively.
(c) Includes ARO related to Sabine and DHLC.
(d) Includes ARO related to asbestos removal.

14. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The tables below represent AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Three Months Ended September 30, 2020						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,053.3	$ 594.8	$ —	$ —	$ —	$ —	$ 1,648.1
Commercial Revenues	559.7	259.2	—	—	—	—	818.9
Industrial Revenues	504.5	93.9	—	—	—	(0.1)	598.3
Other Retail Revenues	41.4	10.0	—	—	—	—	51.4
Total Retail Revenues	2,158.9	957.9	—	—	—	(0.1)	3,116.7
Wholesale and Competitive Retail Revenues:							
Generation Revenues	158.4	—	—	30.5	—	—	188.9
Transmission Revenues (a)	84.4	119.1	317.7	—	—	(276.9)	244.3
Renewable Generation Revenues (b)	—	—	—	15.8	—	(0.3)	15.5
Retail, Trading and Marketing Revenues (c)	—	—	—	447.5	0.9	(24.8)	423.6
Total Wholesale and Competitive Retail Revenues	242.8	119.1	317.7	493.8	0.9	(302.0)	872.3
Other Revenues from Contracts with Customers (b)	34.1	42.8	2.4	0.7	33.9	(43.7)	70.2
Total Revenues from Contracts with Customers	2,435.8	1,119.8	320.1	494.5	34.8	(345.8)	4,059.2
Other Revenues:							
Alternative Revenues (b)	(1.0)	9.3	(2.2)	—	—	6.6	12.7
Other Revenues (b)	—	36.2	—	(4.5)	(2.2)	(35.0)	(5.5)
Total Other Revenues	(1.0)	45.5	(2.2)	(4.5)	(2.2)	(28.4)	7.2
Total Revenues	$ 2,434.8	$ 1,165.3	$ 317.9	$ 490.0	$ 32.6	$ (374.2)	$ 4,066.4

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $246 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $19 million. The remaining affiliated amounts were immaterial.

	Three Months Ended September 30, 2019						
	Vertically Integrated Utilities	**Transmission and Distribution Utilities**	**AEP Transmission Holdco**	**Generation & Marketing**	**Corporate and Other**	**Reconciling Adjustments**	**AEP Consolidated**
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,060.2	$ 588.0	$ —	$ —	$ —	$ —	$ 1,648.2
Commercial Revenues	612.5	290.9	—	—	—	—	903.4
Industrial Revenues	566.0	99.3	—	—	—	1.5	666.8
Other Retail Revenues	49.2	10.6	—	—	—	—	59.8
Total Retail Revenues	2,287.9	988.8	—	—	—	1.5	3,278.2
Wholesale and Competitive Retail Revenues:							
Generation Revenues (a)	231.3	—	—	77.1	—	(34.2)	274.2
Transmission Revenues (b)	77.8	110.9	269.4	—	—	(217.2)	240.9
Renewable Generation Revenues (c)	—	—	—	20.1	—	—	20.1
Retail, Trading and Marketing Revenues (c)	—	—	—	395.3	—	0.5	395.8
Total Wholesale and Competitive Retail Revenues	309.1	110.9	269.4	492.5	—	(250.9)	931.0
Other Revenues from Contracts with Customers (c)	47.3	42.9	4.5	14.8	35.6	(42.2)	102.9
Total Revenues from Contracts with Customers	2,644.3	1,142.6	273.9	507.3	35.6	(291.6)	4,312.1
Other Revenues:							
Alternative Revenues (c)	1.2	5.1	(0.9)	—	—	(16.8)	(11.4)
Other Revenues (c)	—	38.9	—	26.4	(11.2)	(39.8)	14.3
Total Other Revenues	1.2	44.0	(0.9)	26.4	(11.2)	(56.6)	2.9
Total Revenues	$ 2,645.5	$ 1,186.6	$ 273.0	$ 533.7	$ 24.4	$ (348.2)	$ 4,315.0

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $34 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $197 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues.

	Three Months Ended September 30, 2020						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 165.3	$ —	$ 324.2	$ 222.6	$ 429.4	$ 195.8	$ 219.4
Commercial Revenues	78.0	—	138.4	135.8	181.2	94.4	135.0
Industrial Revenues	24.9	—	139.4	139.7	69.1	55.0	83.8
Other Retail Revenues	6.9	—	17.6	1.6	3.1	18.4	2.3
Total Retail Revenues	275.1	—	619.6	499.7	682.8	363.6	440.5
Wholesale Revenues:							
Generation Revenues (a)	—	—	70.3	61.5	—	5.8	42.3
Transmission Revenues (b)	101.8	305.7	30.8	7.4	17.2	8.5	28.7
Total Wholesale Revenues	101.8	305.7	101.1	68.9	17.2	14.3	71.0
Other Revenues from Contracts with Customers (c)	15.2	3.0	16.1	17.7	27.6	4.8	5.6
Total Revenues from Contracts with Customers	392.1	308.7	736.8	586.3	727.6	382.7	517.1
Other Revenues:							
Alternative Revenues (d)	(0.7)	(4.6)	(1.1)	0.4	10.0	(0.5)	0.2
Other Revenues (d)	40.6	—	—	—	3.4	—	—
Total Other Revenues	39.9	(4.6)	(1.1)	0.4	13.4	(0.5)	0.2
Total Revenues	$ 432.0	$ 304.1	$ 735.7	$ 586.7	$ 741.0	$ 382.2	$ 517.3

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $28 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 $243 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $15 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Three Months Ended September 30, 2019						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 192.0	$ —	$ 315.7	$ 198.2	$ 395.6	$ 231.9	$ 222.9
Commercial Revenues	110.6	—	147.2	138.3	180.5	122.2	144.3
Industrial Revenues	32.2	—	152.2	138.7	67.1	84.1	92.3
Other Retail Revenues	7.5	—	18.5	1.9	3.1	24.9	2.3
Total Retail Revenues	342.3	—	633.6	477.1	646.3	463.1	461.8
Wholesale Revenues:							
Generation Revenues (a)	—	—	70.4	102.1	—	21.1	50.7
Transmission Revenues (b)	97.7	256.4	26.2	6.4	13.7	(3.4)	30.0
Total Wholesale Revenues	97.7	256.4	96.6	108.5	13.7	17.7	80.7
Other Revenues from Contracts with Customers (c)	8.2	4.5	18.7	26.6	41.0	5.1	7.0
Total Revenues from Contracts with Customers	448.2	260.9	748.9	612.2	701.0	485.9	549.5
Other Revenues:							
Alternative Revenues (d)	(0.7)	(1.2)	6.6	(1.1)	12.4	7.1	(4.0)
Other Revenues (d)	41.8	—	—	—	(2.8)	—	—
Total Other Revenues	41.1	(1.2)	6.6	(1.1)	9.6	7.1	(4.0)
Total Revenues	$ 489.3	$ 259.7	$ 755.5	$ 611.1	$ 710.6	$ 493.0	$ 545.5

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $32 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $194 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $20 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Nine Months Ended September 30, 2020						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 2,789.1	$ 1,610.6	$ —	$ —	$ —	$ —	$ 4,399.7
Commercial Revenues	1,523.6	792.4	—	—	—	—	2,316.0
Industrial Revenues	1,508.7	290.4	—	—	—	(0.5)	1,798.6
Other Retail Revenues	118.2	32.1	—	—	—	—	150.3
Total Retail Revenues	5,939.6	2,725.5	—	—	—	(0.5)	8,664.6
Wholesale and Competitive Retail Revenues:							
Generation Revenues	447.4	—	—	106.1	—	—	553.5
Transmission Revenues (a)	248.4	341.6	937.7	—	—	(741.7)	786.0
Renewable Generation Revenues (b)	—	—	—	50.7	—	(1.2)	49.5
Retail, Trading and Marketing Revenues (c)	—	—	—	1,133.8	(5.7)	(80.7)	1,047.4
Total Wholesale and Competitive Retail Revenues	695.8	341.6	937.7	1,290.6	(5.7)	(823.6)	2,436.4
Other Revenues from Contracts with Customers (b)	124.1	112.3	17.5	1.7	84.4	(115.7)	224.3
Total Revenues from Contracts with Customers	6,759.5	3,179.4	955.2	1,292.3	78.7	(939.8)	11,325.3
Other Revenues:							
Alternative Revenues (b)	(6.0)	49.2	(77.4)	—	—	3.5	(30.7)
Other Revenues (b)	—	78.1	—	13.2	(6.7)	(71.3)	13.3
Total Other Revenues	(6.0)	127.3	(77.4)	13.2	(6.7)	(67.8)	(17.4)
Total Revenues	$ 6,753.5	$ 3,306.7	$ 877.8	$ 1,305.5	$ 72.0	$ (1,007.6)	$ 11,307.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $725 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $81 million. The remaining affiliated amounts were immaterial.

	Nine Months Ended September 30, 2019						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 2,797.6	$ 1,609.1	$ —	$ —	$ —	$ —	$ 4,406.7
Commercial Revenues	1,641.2	889.4	—	—	—	—	2,530.6
Industrial Revenues	1,647.3	332.6	—	—	—	—	1,979.9
Other Retail Revenues	136.1	32.8	—	—	—	—	168.9
Total Retail Revenues	6,222.2	2,863.9	—	—	—	—	9,086.1
Wholesale and Competitive Retail Revenues:							
Generation Revenues (a)	661.9	—	—	282.0	—	(105.5)	838.4
Transmission Revenues (b)	215.4	324.0	814.3	—	—	(603.6)	750.1
Renewable Generation Revenues (c)	—	—	—	39.0	—	0.5	39.5
Retail, Trading and Marketing Revenues (c)	—	—	—	1,049.5	—	—	1,049.5
Total Wholesale and Competitive Retail Revenues	877.3	324.0	814.3	1,370.5	—	(708.6)	2,677.5
Other Revenues from Contracts with Customers (c)	128.8	127.6	12.6	4.5	80.4	(113.6)	240.3
Total Revenues from Contracts with Customers	7,228.3	3,315.5	826.9	1,375.0	80.4	(822.2)	12,003.9
Other Revenues:							
Alternative Revenues (c)	(55.7)	21.5	(18.6)	—	—	(60.3)	(113.1)
Other Revenues (c)	—	117.3	—	53.2	(6.7)	(109.2)	54.6
Total Other Revenues	(55.7)	138.8	(18.6)	53.2	(6.7)	(169.5)	(58.5)
Total Revenues	$ 7,172.6	$ 3,454.3	$ 808.3	$ 1,428.2	$ 73.7	$ (991.7)	$ 11,945.4

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $105 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $596 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues.

	Nine Months Ended September 30, 2020						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 447.8	$ —	$ 954.4	$ 610.8	$ 1,162.6	$ 463.5	$ 498.7
Commercial Revenues	285.2	—	390.6	376.0	507.3	247.8	351.2
Industrial Revenues	91.4	—	415.0	408.2	199.1	170.8	245.9
Other Retail Revenues	22.3	—	50.9	5.0	9.8	51.2	6.6
Total Retail Revenues	846.7	—	1,810.9	1,400.0	1,878.8	933.3	1,102.4
Wholesale Revenues:							
Generation Revenues (a)	—	—	185.3	215.5	—	9.9	106.7
Transmission Revenues (b)	290.4	902.6	91.5	22.1	51.1	20.2	87.5
Total Wholesale Revenues	290.4	902.6	276.8	237.6	51.1	30.1	194.2
Other Revenues from Contracts with Customers (c)	33.4	17.5	46.8	60.6	78.9	23.2	21.1
Total Revenues from Contracts with Customers	1,170.5	920.1	2,134.5	1,698.2	2,008.8	986.6	1,317.7
Other Revenues:							
Alternative Revenues (d)	(0.3)	(82.3)	(11.9)	5.4	49.6	1.5	0.5
Other Revenues (d)	86.9	—	—	—	13.3	—	—
Total Other Revenues	86.6	(82.3)	(11.9)	5.4	62.9	1.5	0.5
Total Revenues	$ 1,257.1	$ 837.8	$ 2,122.6	$ 1,703.6	$ 2,071.7	$ 988.1	$ 1,318.2

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $85 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 $715 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $49 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Nine Months Ended September 30, 2019						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 454.9	$ —	$ 944.7	$ 558.8	$ 1,155.5	$ 519.6	$ 503.7
Commercial Revenues	314.5	—	421.5	371.4	573.7	304.3	371.1
Industrial Revenues	98.8	—	444.3	411.9	233.9	238.1	257.2
Other Retail Revenues	22.7	—	56.5	5.4	9.8	63.1	6.7
Total Retail Revenues	890.9	—	1,867.0	1,347.5	1,972.9	1,125.1	1,138.7
Wholesale Revenues:							
Generation Revenues (a)	—	—	200.1	327.4	—	35.5	152.7
Transmission Revenues (b)	282.0	775.3	77.6	18.8	42.0	21.9	78.0
Total Wholesale Revenues	282.0	775.3	277.7	346.2	42.0	57.4	230.7
Other Revenues from Contracts with Customers (c)	22.9	12.6	48.2	76.2	113.3	16.7	20.1
Total Revenues from Contracts with Customers	1,195.8	787.9	2,192.9	1,769.9	2,128.2	1,199.2	1,389.5
Other Revenues:							
Alternative Revenues (d)	(0.4)	(17.8)	11.2	(1.4)	22.0	(25.3)	(47.4)
Other Revenues (d)	122.6	—	—	—	3.8	—	—
Total Other Revenues	122.2	(17.8)	11.2	(1.4)	25.8	(25.3)	(47.4)
Total Revenues	$ 1,318.0	$ 770.1	$ 2,204.1	$ 1,768.5	$ 2,154.0	$ 1,173.9	$ 1,342.1

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $96 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $587 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $57 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues.

Fixed Performance Obligations

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of September 30, 2020. 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	$ 263.8	$ 188.3	$ 164.2	$ 223.4	$ 839.7
AEP Texas	108.2	—	—	—	108.2
AEPTCo	274.8	—	—	—	274.8
APCo	40.1	33.1	26.6	11.6	111.4
I&M	8.6	10.9	8.8	4.5	32.8
OPCo	16.5	5.3	—	—	21.8
PSO	3.8	—	—	—	3.8
SWEPCo	10.3	—	—	—	10.3

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have material contract assets as of September 30, 2020 and December 31, 2019.

When the Registrants receive consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have material contract liabilities as of September 30, 2020 and December 31, 2019.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrant Subsidiaries' balance sheets within the Accounts Receivable - Customers line item. The Registrant Subsidiaries' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of September 30, 2020 and December 31, 2019. See "Securitized Accounts Receivable - AEP Credit" section of Note 12 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	September 30, 2020	December 31, 2019
	(in millions)	
AEPTCo	$ 79.9	$ 65.9
APCo	49.3	47.3
I&M	30.5	37.1
OPCo	36.5	33.9
PSO	11.0	9.7
SWEPCo	18.4	17.6

CONTROLS AND PROCEDURES

During the third quarter of 2020, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of September 30, 2020, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2020 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see "Commitments, Guarantees and Contingencies," of Note 5 incorporated herein by reference.

Item 1A. Risk Factors

The AEP 2019 Annual Report on Form 10-K includes a detailed discussion of risk factors.As of September 30, 2020, the risk factors appearing in AEP's 2019 Annual Report are supplemented and updated as follows:

AEP's Financial Condition and Results of Operations could continue to be Adversely Affected by the Ongoing Coronavirus Pandemic

AEP is responding to the global 2019 novel coronavirus (COVID-19) pandemic by taking steps to mitigate the potential risks posed by its spreadIts rapid spread around the world and throughout the United States prompted many countries, including the United States, to institute restrictions on travel, public gatherings and certain business operations. These restrictions continue to disrupt economic activity in AEP's service territory and could reduce future demand for energy, particularly from commercial and industrial customers. AEP provides a critical service to its customers which means that it must keep its employees who operate its businesses safe and minimize unnecessary risk of exposure to the virus. AEP has updated and implemented a company-wide pandemic plan to address specific aspects of the coronavirus pandemic. This plan guides AEP's emergency response, business continuity, and the precautionary measures that AEP is taking on behalf its employees and the public. AEP has taken extra precautions for its employees who work in the field and for employees who continue to work in its facilities, and AEP has implemented work from home policies where appropriate.

Continuing adverse economic conditions may result in the inability of customers to pay for electric service, which could affect revenue recognition and the collectability of accounts receivable. These conditions might also impact the Registrants' access to and cost of capital. This is a rapidly evolving situation that could lead to extended disruption of economic activity in AEP's markets.

AEP has instituted measures to ensure its supply chain remains open; however, there could be global shortages that will impact AEP's maintenance and capital programs that AEP currently cannot anticipate. AEP will continue to monitor developments affecting both its workforce and its customers, and will take additional precautions that are determined to be necessary in order to mitigate the impacts.

AEP continues to implement strong physical and cyber security measures to ensure that its systems remain functional in order to both serve its operational needs with a remote workforce and keep them running to ensure uninterrupted service to customers.

In addition, the economic disruptions caused by COVID-19 could also adversely impact the impairment risks for certain long-lived assets, equity method investments and goodwill. Market volatility and reduction in collections coupled with longer collection periods due to the expansion of customer payment arrangements could reduce cash from operations and cause an adverse impact to liquidity.

AEP will continue to review and modify its plans as conditions change. Despite AEP's efforts to manage these impacts, their ultimate impact also depends on factors beyond AEP's knowledge or control, including the duration and severity of this outbreak, its impact on economic and market conditions, as well as third-party actions taken to contain its spread and mitigate its public health effects. Therefore, AEP currently cannot estimate the potential impact to its financial position, results of operations and cash flows.

Ohio House Bill 6 (HB 6), which provides for beneficial cost recovery for OPCo and for plants owned by OVEC, has come under public scrutiny (Applies to AEP and OPCo)

In 2019, Ohio adopted and implemented HB 6.Among other provisions, HB 6 phased out current energy efficiency including lost shared savings revenues of $26 million annually and renewable mandates no later than 2020 and after 2026, respectively. HB 6 also provided for the recovery of existing renewable energy contracts on a bypassable basis through 2032, and included a provision for recovery of OVEC coal-fired unit costs through 2030. AEP and OPCo engaged in lobbying efforts and provided testimony during the legislative process in support of HB 6.In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of the Speaker of the Ohio House of Representatives, Larry Householder, four other individuals, and Generation Now, an entity registered as a 501(c)(4) social welfare organization, in connection with an alleged racketeering conspiracy involving the adoption of HB 6. In light of the allegations in the indictment, proposed legislation has been introduced that would repeal HB 6. The outcome of the U.S. Attorney's Office investigation and its impact on HB 6 is not known.If the provisions of HB 6 were to be eliminated, it is unclear whether and in what form the Ohio General Assembly would pass new legislation addressing similar issues. 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. In addition, the impact of continued public scrutiny of HB 6 is not known, and may have an adverse impact on AEP and OPCo, including their relationship with regulatory and legislative authorities, customers and other stakeholders and their potential involvement with various current or future litigation arising out HB 6.

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 September 30, 2020, OVEC has outstanding indebtedness of approximately $1.3 billion, of which APCo, I&M, and OPCo are collectively responsible for $563 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.

Energy Harbor (formerly FirstEnergy Solutions), a nonaffiliated party, whose aggregate power participation ratio is 4.85% under the ICPA, filed a petition seeking protection under the bankruptcy law. In May 2020, Energy Harbor entered into a bankruptcy settlement and resumed performance under the ICPA as of June 1, 2020. In July 2020, federal prosecutors arrested the Speaker of the Ohio House of Representatives and four other individuals alleging that they engaged in a bribery and money laundering scheme connected to the passage of HB 6. Subsequently, proposed legislation was introduced that would repeal HB 6. If HB 6 is repealed and not replaced, Energy Harbor's financial ability to participate in the ICPA could be adversely impacted. Management is currently unable to predict the outcome of the proposed legislation and will continue to monitor the legislative process and any potential impact to OVEC's cash flows or financial condition. 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%.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations.The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act.Exhibit 95 "Mine Safety Disclosure Exhibit" contains the notices of violation and proposed assessments received by DHLC under the Mine Act for the quarter ended September 30, 2020.

Item 5. Other Information

On October 21, 2020, the Company entered into a separation, release of all claims and noncompetition agreement with Ms. Hillebrand pursuant to which the Company will provide $1,106,875 in severance benefits due to the elimination of her position and separation from service, effective December 31, 2020. This amount is equivalent to 1× her annual base salary and target annual incentive award, which is the current severance benefit for all participants under AEP's Executive Severance plan. Half of this amount will be paid 6 months after her termination date and the remainder will be paid over the following 13 biweekly pay periods. In addition, the Company agreed to provide $500,000 in unrestricted AEP shares under AEP's Long-Term Incentive Plan upon her separation from AEP service. The number of unrestricted AEP shares provided to Ms. Hillebrand will be determined by dividing the $500,000 value by the closing price of AEP Common Stock as reported by NASDAQ on December 31, 2020 and will be granted under AEP's Long-Term Incentive Plan. This agreement also contains among other provisions, a one-year non-competition agreement and affirms certain non-solicitation, confidentiality and cooperation stipulations.

Item 6. Exhibits

The documents designated with an (*) below have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof.

Exhibit	Description	Previously Filed as Exhibit to:
AEP‡ File No. 1-3525		
4.1	Purchase Contract dated as of August 14, 2020, 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 dated August 14, 2020 Exhibit 4.1
4.2	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, Exhibits 4(c) and 4(d); Form 8-K, Exhibit 4.3, dated March 19, 2019
4.3	Supplemental Indenture No. 2, dated August 14, 2020, from the Company to The Bank of New York Mellon Trust Company, N.A., as trustee	Form 8-K dated August 14, 2020 Exhibit 4.3
SWEPCo‡ File No. 1-3146		
4.4	Amendment to Certificate of Incorporation filed with Delaware Secretary of State effective August 31, 2020 to authorize a reverse stock split of the common stock, eliminate the authorized preferred stock and reduce the authorized number of shares of common stock	Form 8-K dated September 1, 2020 Exhibit 3.1

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
10.1	AEP System Stock Ownership Requirement Plan As Amended and Restated Effective October 1, 2020	X							
10.2	AEP Retainer Deferral Plan For Non-Employee Directors As Amended and Restated Effective October 1, 2020	X							
10.3	AEP Stock Unit Accumulation Plan For Non-Employee Directors As Amended Effective October 1, 2020	X							
10.4	Severance, Stock Award, Release of All Claims and Noncompetition Agreement dated October 21, 2020 between AEPSC and Lana Hillebrand	X							
31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
95	Mine Safety Disclosures								X

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
101.INS	XBRL Instance Document	The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.							
101.SCH	XBRL Taxonomy Extension Schema	X	X	X	X	X	X	X	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X	X	X	X	X	X	X	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase	X	X	X	X	X	X	X	X
101.LAB	XBRL Taxonomy Extension Label Linkbase	X	X	X	X	X	X	X	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	X	X	X	X	X	X	X	X
104	Cover Page Interactive Data File	Formatted as Inline XBRL and contained in Exhibit 101.							

SIGNATURE

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

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

AEP TEXAS INC.
AEP TRANSMISSION COMPANY, LLC
APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: October 22, 2020