Appendix A to the
Proxy Statement

American Electric Power

2020 Annual Report

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

AMERICAN ELECTRIC POWER®

BOUNDLESS ENERGY℠

CONTENTS

AMERICAN ELECTRIC POWER
1 Riverside Plaza
Columbus, Ohio 43215-2373

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 East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP Energy Supply, LLC	A nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
AEP OnSite Partners	A division of AEP Energy Supply, LLC that builds, owns, operates and maintains customer solutions utilizing existing and emerging distributed technologies.
AEP Renewables	A division of AEP Energy Supply, LLC that develops and/or acquires large scale renewable projects that are backed with long-term contracts with creditworthy counter parties.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEP Utilities	AEP Utilities, Inc., a former subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. Effective December 31, 2016, TCC and TNC were merged into AEP Utilities, Inc. Subsequently following this merger, the assets and liabilities of CSW Energy, Inc. were transferred to a competitive affiliate company and AEP Utilities, Inc. was renamed AEP Texas Inc.
AEP Wind Holdings LLC	Acquired in April 2019 as Sempra Renewables LLC, develops, owns and operates, or holds interests in, wind generation facilities in the United States.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in deregulated markets.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AEPTHCo	AEP Transmission Holding Company, LLC, a subsidiary of AEP, an intermediate holding company that owns transmission operations joint ventures and AEPTCo.
AFUDC	Allowance for Equity Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
ALJ	Administrative Law Judge.
AMI	Advanced Metering Infrastructure.
AMT	Alternative Minimum Tax.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.

Term	Meaning
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.
APTCo	AEP Appalachian Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
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.
CAA of 2021	Consolidated Appropriations Act of 2021 signed into law in December 2020.
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.
Conesville Plant	A retired, single unit coal-fired generation plant totaling 651 MW located in Conesville, Ohio. The plant was jointly-owned by AGR and a nonaffiliate.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,288 MW nuclear plant owned by I&M.
COVID-19	Coronavirus 2019, a highly infectious respiratory disease. In March 2020, the World Health Organization declared COVID-19 a worldwide pandemic.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSAPR	Cross-State Air Pollution Rule.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
CWA	Clean Water Act.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel IX, DCC Fuel X, DCC Fuel XI, DCC Fuel XII, DCC Fuel XIII, DCC Fuel XIV and DCC Fuel 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.
DIR	Distribution Investment Rider.
DOE	U. S. Department of Energy.
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.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.

Term	Meaning
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
Global Settlement	In February 2017, the PUCO approved a settlement agreement filed by OPCo in December 2016 which resolved all remaining open issues on remand from the Supreme Court of Ohio in OPCo's 2009 - 2011 and June 2012 - May 2015 ESP filings. It also resolved all open issues in OPCo's 2009, 2014 and 2015 SEET filings and 2009, 2012 and 2013 FAC Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IMTCo	AEP Indiana Michigan Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
kV	Kilovolt.
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.
NERC	North American Electric Reliability Corporation.
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.
NO_2	Nitrogen dioxide.
NOL	Net operating losses.
NO_x	Nitrogen oxide.
NPDES	National Pollutant Discharge Elimination System.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property. In July 2019, the Ohio Phase-in Recovery funding securitization bonds matured.

Term	Meaning
OHTCo	AEP Ohio Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
Oklaunion Power Station	A retired, single unit coal-fired generation plant totaling 650 MW located in Vernon, Texas. The plant was jointly-owned by AEP Texas, PSO and certain nonaffiliated entities.
OKTCo	AEP Oklahoma Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
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.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
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 and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
REP	Texas Retail Electric Provider.
Restoration Funding	AEP Texas Restoration Funding LLC, a wholly-owned subsidiary of AEP Texas and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Texas primarily caused by Hurricane Harvey.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated 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 MW wind generation facility in west Texas in which AEP owns an 85% interest.

Term	Meaning
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019, consists of 724 MWs of wind generation and battery assets in the United States.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
SWTCo	AEP Southwestern Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
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.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
TCC	Formerly AEP Texas Central Company; now a division of AEP Texas.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	Formerly AEP Texas North Company; now a division of AEP Texas.
Transition Funding	AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. In July 2020, the final AEP Texas Central Transition Funding II LLC securitization bond matured.
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 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UMWA	United Mine Workers of America.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.
WVTCo	AEP West Virginia Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.

FORWARD-LOOKING INFORMATION

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

- Changes in economic conditions, electric market demand and demographic patterns in AEP service territories.
- 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, including favorable tax treatment, and to recover those costs.
- New legislation, litigation and government regulation, including changes to tax laws and regulations, oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or PM and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including coal ash and nuclear fuel.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- The ability to constrain operation and maintenance costs.
- Prices and demand for power generated and sold at wholesale.
- Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.
- The ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within RTOs including ERCOT, PJM and SPP.
- Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.

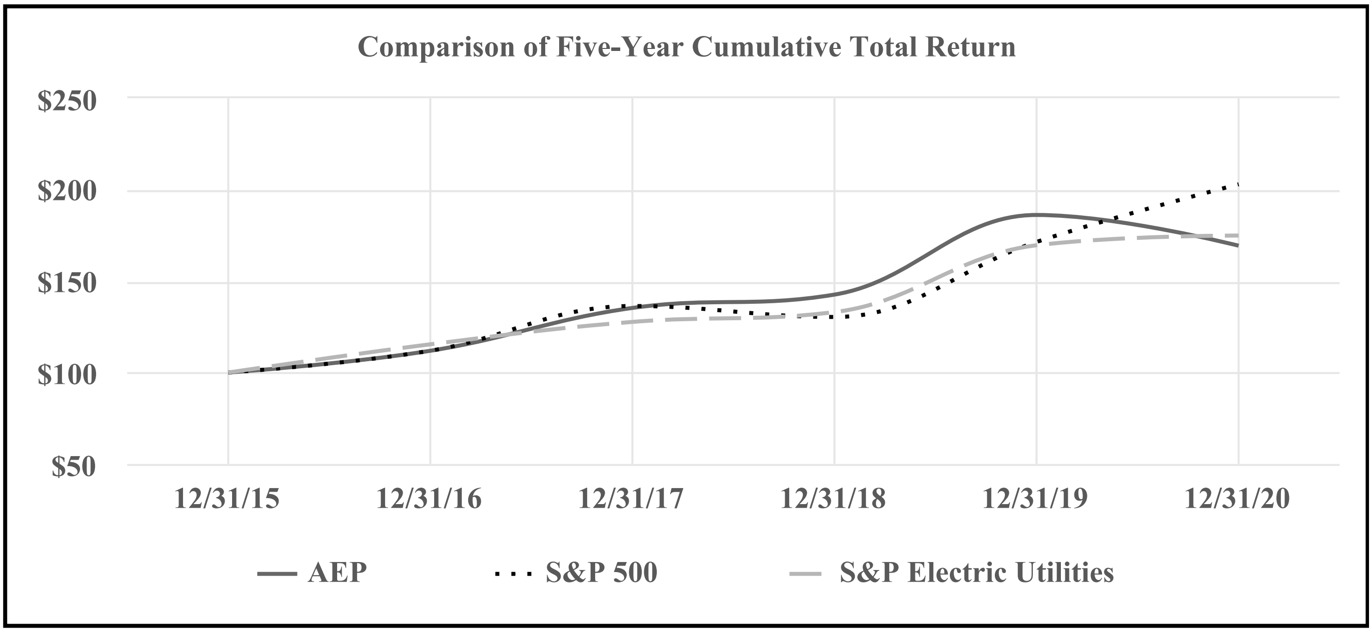
- The impact of volatility in the capital markets on the value of the investments held by the pension, OPEB, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
- Accounting standards periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber security threats and other catastrophic events.
- The ability to attract and retain the requisite work force and key personnel.

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

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

AEP COMMON STOCK INFORMATION

AEP common stock is principally traded using the trading symbol "AEP" on the NASDAQ Stock Market. As of December 31, 2020, AEP had 55,475 registered shareholders. The performance graph below compares the cumulative total return among AEP, the S&P 500 Index and the S&P Electric Utilities Index over a five year period. The performance graph assumes an initial investment of $100 on December 31, 2015 and that all dividends were reinvested.



Source: S&P Dow Jones Indices LLC. Data as of December 31, 2020. Past performance is no guarantee of future results. Chart provided for illustrative purposes.

EXECUTIVE OVERVIEW

Company Overview

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

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

- Approximately 223,000 circuit miles of distribution lines that deliver electricity to 5.5 million customers.
- Approximately 40,000 circuit miles of transmission lines, including approximately 2,200 circuit miles of 765 kV lines, the backbone of the electric interconnection grid in the eastern United States.
- Approximately 22,000 MWs of regulated owned generating capacity and approximately 4,700 MWs of regulated PPA capacity in 2 RTOs as of December 31, 2020, one of the largest complements of generation in the United States.

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 reduced demand for energy, particularly from commercial and industrial customers in 2020. Although AEP cannot predict the severity or duration of the impact of the COVID-19 pandemic, AEP currently anticipates a 0.2% increase in weather-normalized retail sales volume in 2021 as compared to 2020. For the year ended December 31, 2020, AEP experienced a reduction in weather-normalized retail sales volume of 2.2% as compared to the same period in 2019 primarily driven by a 5.7% decrease in the industrial customer class and a 4.2% decrease in the commercial customer class offset by an increase in demand of 3.2% from the residential customer class. The reduction in weather-normalized retail sales volume of 2.2% did not result in a significant decrease in the corresponding retail margins for the year ended December 31, 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 quarters of 2020, most state regulators began to lift restrictions on disconnects. As of December 31, 2020, AEP had resumed disconnections in its regulated jurisdictions with the exception of Virginia, Kentucky and Arkansas. Disconnections resumed in Kentucky during January 2021. AEP continues to work with regulators and stakeholders in Virginia and Arkansas and management currently anticipates resuming customary disconnection practices in the first half of 2021. 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.

Throughout 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, but has continued to improve throughout the fourth quarter of 2020 as disconnect moratoriums have ended in most jurisdictions. Accounts receivable aging is also improving due to AEP proactively engaging with customers to collect payments or establish payment arrangements for outstanding balances. AEP has received, from the states of Virginia and West Virginia, \$10 million and \$20 million, respectively, to apply to residential customer balances that are past-due. In addition, customers in other states have access to various programs that assist customers who have accumulated larger than normal past-due balances. As of December 31, 2020, AEP currently does not expect accounts receivable 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 December 31, 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, the affiliated utility subsidiary would no longer participate in the receivables securitization agreement and the Registrants would need to rely on additional sources of funding for operation and working capital, which may adversely impact liquidity. The receivables that are ineligible under the receivables securitization agreement are financed with short-term debt at AEP Credit.

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 COVID-19 orders, granting deferral authority for incremental COVID-19 expenses, with the exception of Kentucky and 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 December 31, 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 December 31, 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 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. The \$1 billion 364-day term loan was repaid in the fourth quarter of 2020. In addition, during 2020, AEP issued approximately \$5.6 billion in long-term debt. As of December 31, 2020, AEP's available liquidity was \$2.5 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 AMT Credit Refund, (b) a 5-year NOL carryback from years 2018-2020 and (c) delayed payment of employer payroll taxes. Pursuant to the CARES Act, AEP, APCo and OPCo requested and in July received refunds of AMT credit of $20 million, $7 million and $9 million, respectively. 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 Act. AEP carried back a 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 $48 million primarily at the Generation & Marketing segment. Management will continue to monitor potential legislation and any impacts to the AMT Credit and NOL refunds that were filed in 2020 pursuant to the CARES Act. The Registrants deferred 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 December 31, 2020, the Registrants have deferred $55 million of the employer share of payroll taxes.

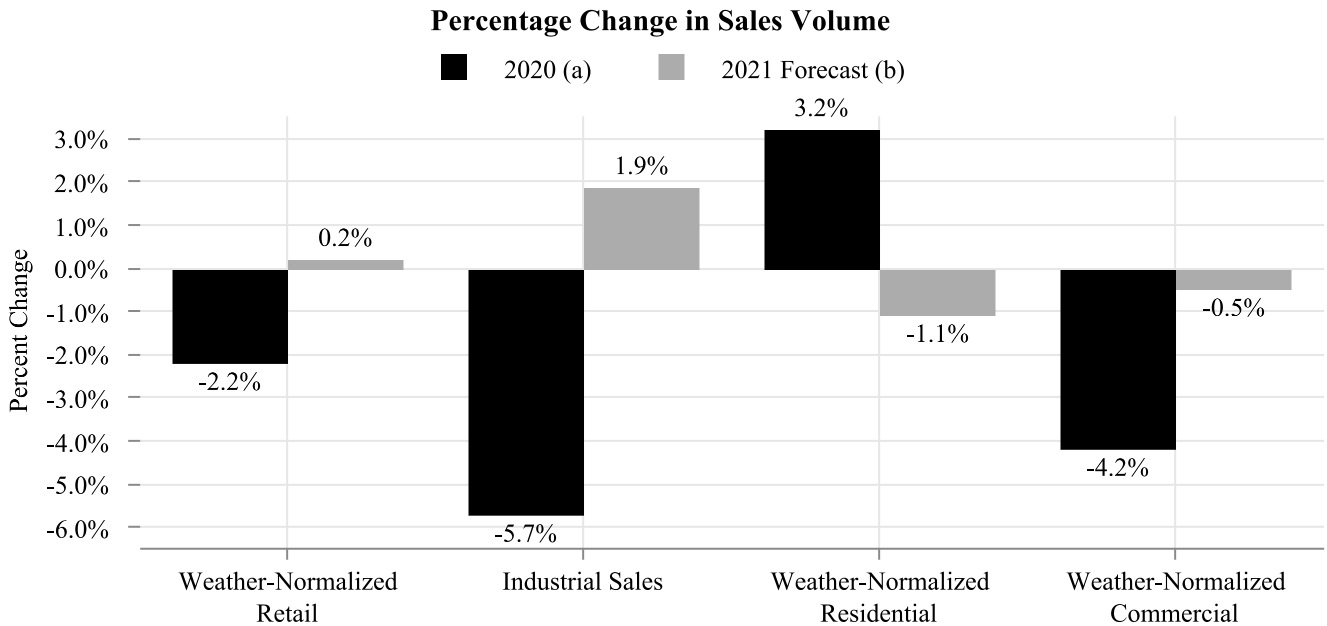
In December 2020, the CAA of 2021 was signed into law. The CAA of 2021 includes: (a) COVID-19 tax relief and tax extender provisions including extensions of time to begin construction on and placed in-service assets generating PTCs and ITCs, (b) 100% deductibility of business meals in 2021 and 2022 and (c) an extension of the work opportunity tax credit. The ITC percentage has been increased for projects starting construction through 2023 and placed in-service by the end of 2025. The PTC has been extended for an additional year, to include projects started in 2021 and completed in 2025. These provisions provide time and flexibility on the construction start and in-service dates.

The Registrants have taken 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 December 31, 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 year ended December 31, 2020 decreased by 2.2% from the year ended December 31, 2019. Weather-normalized residential sales increased 3.2% for the year ended December 31, 2020 compared to the year ended December 31, 2019. AEP's 2020 industrial sales volumes decreased 5.7% compared to 2019. The decline in industrial sales was spread across many industries. Weather-normalized commercial sales decreased by 4.2% in 2020 compared to 2019.

In 2021, AEP anticipates weather-normalized retail sales volumes will increase by 0.2%. The industrial class is expected to increase by 1.9% in 2021, while weather-normalized residential sales volumes are projected to decrease by 1.1%. Finally, AEP projects weather-normalized commercial sales volumes to decrease by 0.5%.



(a) Percentage change for the year ended December 31, 2020 as compared to the year ended December 31, 2019.
(b) Forecasted percentage change for the year ended December 31, 2021 compared to the year ended December 31, 2020.

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 customers. In 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 deemed 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 November 2020, the Virginia SCC issued an order concluding that APCo earned above its authorized ROE but within its ROE band for the 2017-2019 period, resulting in no refund to customers and no change to APCo base rates on a prospective basis. The Virginia SCC also disagreed with APCo's treatment of the retired coal-fired generation assets for regulatory purposes, and instead adopted the Virginia SCC Staff's recommendation to treat the remaining unrecovered costs of the retired coal-fired generation assets as a regulatory asset to be amortized over 10 years as of the June 2015 retirement date. The Virginia SCC's adoption of the Staff's recommended regulatory treatment of the coal-fired generation assets resulted in a net $40 million increase to APCo's 2020 pretax income. In addition, the Virginia SCC's order also included: (a) implementation of the Staff-modified APCo 2017 depreciation study effective January 1, 2018 and (b) implementation of the Staff-modified APCo 2019 depreciation study effective January 1, 2020. The adoption of these depreciation studies resulted in an approximate $47 million reduction to APCo's 2020 pretax income comprised of a $44 million reduction to revenues for amounts recognized in advance of the recording of depreciation expense for the periods January 2018 through October 2020 and a $3 million increase in depreciation expense for the periods November and December 2020. A corresponding regulatory liability was recorded for the $44 million reduction to revenues. Also in November 2020, APCo filed a notice of appeal of the Virginia SCC's order with the Virginia Supreme Court. In December 2020, an intervenor filed a petition at the Virginia SCC requesting reconsideration of: (a) the failure of the Virginia SCC to apply a threshold earnings test to the approved regulatory asset for APCo's closed coal-fired generation assets, (b) the Virginia SCC's use of a 2011 benchmark study to measure the replacement value of capacity for purposes of APCo's 2017 – 2019 earnings test and (c) the reasonableness and prudency of APCo's investments in AMI meters. Also in December 2020, APCo filed a petition at the Virginia SCC requesting reconsideration of: (a) certain issues related to APCo's going-forward rates and (b) the Virginia SCC's decision to deny APCo tariff changes that align rates with underlying costs. For APCo's going-forward rates, APCo requested that the Virginia SCC clarify its final order and whether APCo's current rates will allow it to earn a fair return. If the Virginia SCC's order did conclude on APCo's ability to earn a fair return through existing base rates, APCo further requested that the Virginia SCC clarify whether it has the authority to also permit an increase in base rates. If the Virginia SCC did not conclude on APCo's ability to earn a fair return, APCo requested the Virginia SCC provide such a conclusion. In January 2021, as requested by the Virginia SCC, APCo filed briefs related to the petition for reconsideration.

- *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. In November 2020, PUCO staff filed testimony supporting an annual revenue decrease ranging from $102 million to $123 million based upon an ROE of 8.76% to 9.78%. The staff's proposal included a disallowance of plant in-service which could result in a write-off of up to $27 million. In addition, the staff recommended that capitalized incentives be excluded from base rates prospectively and also recommended annual revenue caps for the DIR of $57 million in 2021, $78 million in 2022, $96 million in 2023 and $46 million for the first five months of 2024. In December 2020, OPCo and intervenors filed objections. A procedural schedule for the case is pending due to ongoing settlement discussions.

- *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. As of December 31, 2020, management estimates that SWEPCo has incurred incremental other operation and maintenance expenses of $84 million ($82 million of which has been deferred as a regulatory asset related to the Louisiana jurisdiction) and incremental capital expenditures of $23 million, all of which is 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 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 held in December 2020. SWEPCo expects a decision from the Texas Supreme Court in 2021. As of December 31, 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 programs as of December 31, 2020, including shared savings revenues of $26 million annually and renewable mandates after 2026. 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. In January and February 2021, two AEP shareholders filed two derivative actions purporting to assert claims on behalf of AEP against certain AEP officers and directors based on allegations similar to those in the putative securities class action. 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 incurred through 2020 or incurs significant costs defending against the securities class action or the derivative actions, 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.

- In December 2020, APCo and WPCo filed a proposal with the WVPSC to implement an investment tracker surcharge mechanism for recovering costs associated with capital investment made between base rate cases. The initial filing requests a total annual increase of $50 million ($41 million related to APCo), which represents recovery of costs associated with infrastructure investments made over an approximate three-year period since the companies' last base rate case filing in 2018. The filing also proposes that APCo and

WPCo could submit annual filings with requested increases capped to a percentage of total retail revenues (3.5% in the first year and 3% in subsequent filings with an overall cap of 9.5%). If a future base rate case is filed, the surcharge would reset to zero on implementation of the new rates. In January 2021, WVPSC staff filed a motion recommending that the WVPSC reject the proposal. If APCo and WPCo do not receive approval to recover these incremental investments through the proposed tracker surcharge mechanism between base rate cases, it could cause a temporary reduction in future net income and cash flows and impact financial condition until APCo and WPCo can seek approval in their next base rate case.

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) (in millions)		Approved ROE	New Rates Effective
I&M	Michigan	$ 36.4	(a)	9.86%	February 2020
I&M	Indiana	60.0	(b)	9.7%	March 2020
AEP Texas	Texas	(40.0)		9.4%	June 2020
APCo	Virginia	—	(c)	9.2%	February 2021
KPCo	Kentucky	52.7		9.3%	January 2021

(a) See "2019 Michigan Base Rate Case" section of Note 4 Rate Matters in the 2019 Annual Report for additional information.
(b) Phased-in through an increase in base rates which included: (a) an annual increase in base rates of \$44 million effective March 2020 and (b) an annual increase in base rates of \$60 million effective January 2021 based on the IURC-approved forecast of December 31, 2020 Indiana jurisdictional electric plant in-service. The order rejected I&M's proposed re-allocation of capacity costs related to the loss of a significant FERC wholesale contract, which negatively impacted I&M's annual pretax earnings by approximately \$20 million starting June 2020.
(c) APCo filed a notice of appeal with the Virginia Supreme Court and a petition requesting reconsideration with the Virginia SCC. In addition, an intervenor has also filed a petition requesting reconsideration with the Virginia SCC.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase (in millions)		Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE
OPCo	Ohio	June 2020	$ 42.3		10.15%	8.76% - 9.78%
SWEPCo	Texas	October 2020	105.0	(a)	10.35%	(b)
SWEPCo	Louisiana	December 2020	134.0		10.35%	(c)

(a) 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.
(b) Intervenor and staff testimony is scheduled to be filed in March and April 2021, respectively.
(c) Awaiting procedural schedule.

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 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 rates. SWEPCo's share of the net investment in the Dolet Hills Power Station is $151 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 fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $131 million as of December 31, 2020. Also, as of December 31, 2020, SWEPCo had a net over-recovered fuel balance of $35 million, which includes fuel burned at the Dolet Hills Power Station. Additional operational and land-related costs are expected to be incurred by DHLC and Oxbow and billed to SWEPCo prior to the closure of the Dolet Hills Power Station and recovered through fuel clauses.

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.

Pirkey Power Plant and Related Fuel Operations

In November 2020, management announced plans to retire the Pirkey Power Plant in 2023. The Pirkey Power Plant costs are recoverable by SWEPCo through base rates. SWEPCo's share of the net investment in the Pirkey Power Plant is $212 million, including CWIP, before cost of removal. Sabine is a mining operator providing mining services to the Pirkey Power Plant. Under the provisions of the mining agreement, SWEPCo is required to pay, as part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. SWEPCo expects fuel deliveries, including billings of all fixed and operating costs, from Sabine to cease during the first quarter of 2023. Under the fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $193 million as of December 31, 2020. Also, as of December 31, 2020, SWEPCo had a net over-recovered fuel balance of $35 million, which includes fuel burned at the Pirkey Power Plant. Additional operational costs are expected to be incurred by Sabine and billed to SWEPCo, as well as land-related costs incurred by SWEPCo, prior to the closure of the Pirkey Power Plant and recovered through fuel clauses.

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

Renewable Generation

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

Contracted Renewable Generation Facilities

AEP continues to develop its renewable portfolio within the Generation & Marketing segment. Activities include working directly with wholesale and large retail customers to provide tailored solutions based upon market knowledge, technology innovations and deal structuring which may include distributed solar, wind, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other forms of cost reducing energy technologies. The Generation & Marketing segment also develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with creditworthy counterparties.

In November 2020, AEP acquired an additional 10% interest, or approximately 30 MWs, in Santa Rita East. The project is located in west Texas and was placed in-service in July 2019. Long-term virtual power purchase agreements are in place with nonaffiliates for the project's generation. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

In November 2020, AEP signed a Purchase and Sale Agreement with a nonaffiliate to acquire a 75% interest in the 100 MW Dry Lake Solar Project located in southern Nevada. Management expects the transaction to close in the first quarter of 2021 and the solar project is expected to be in-service in the second quarter of 2021.

As of December 31, 2020, subsidiaries within AEP's Generation & Marketing segment had approximately 1,549 MWs of contracted renewable generation projects in-service. In addition, as of December 31, 2020, these subsidiaries had approximately 137 MWs of renewable generation projects under construction with total estimated capital costs of $208 million related to these projects.

Regulated Renewable Generation Facilities

In 2020, PSO received approval from the OCC and SWEPCo received approval from the APSC and LPSC to acquire the North Central Wind Energy Facilities, comprised of three Oklahoma wind facilities totaling 1,485 MWs, on a fixed cost turn-key basis at completion. Both the APSC and LPSC approved the flex-up option, agreeing to acquire the Texas portion, which the PUCT denied. 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 does satisfy 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.

Having regulatory approval, and the expectation that all three wind facilities will be eligible for the IRS extension of the "Continuity Safe Harbor," PSO and SWEPCo are proceeding with the full 1,485 MW development of these three projects. The 199 MW wind facility is targeted to be acquired and placed in-service in March 2021. The 287 MW wind facility is targeted to be acquired and placed in-service in December 2021 and the 999 MW wind facility is targeted to be acquired and placed in-service between December 2021 and April 2022.

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. In December 2020, management decided they would only proceed with the potential sale of Racine. The two Racine units have a net maximum capacity of 48 MWs and the net book value is $45 million as of December 31, 2020. In February 2021, AEP signed an agreement to sell Racine to a nonaffiliated party. The sale of Racine requires FERC approval. The sale is expected to close in the second quarter of 2021 and result in an immaterial gain. Racine was not presented as Held for Sale on AEP's Consolidated Balance Sheets due to immateriality.

Federal Tax Reform

Based on current regulatory orders received, management anticipates amortization of $233 million of Excess ADIT in 2021 ($64 million of Excess ADIT subject to normalization requirements and $169 million of Excess ADIT that is not subject to normalization requirements). Customer usage or new regulatory orders could result in changes to these estimates. Management anticipates amortizing the following ranges of Excess ADIT that is not subject to normalization requirements during the years 2022 through 2026:

Annual Amortization of Excess ADIT
Not Subject to Normalization Requirements

Year	Range		
	(in millions)		
2022	$ 75.0	-	$ 105.0
2023	68.0	-	98.0
2024	35.0	-	65.0
2025	5.0	-	26.0
2026	5.0	-	25.0

Merchant Portion of Turk Plant

SWEPCo constructed the Turk Plant, a base load 600 MW (650 MW net maximum capacity) pulverized coal ultra-supercritical generating unit in Arkansas, which was placed in-service in December 2012 and is included in the Vertically Integrated Utilities segment. SWEPCo owns 73% (440 MWs/477 MWs) of the Turk Plant and operates the facility.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This share of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under cost-based rate recovery in Texas, Louisiana and through SWEPCo's wholesale customers under FERC-based rates. As of December 31, 2020, the net book value of Turk Plant was $1.4 billion, before cost of removal, including materials and supplies inventory and CWIP. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

FERC Transmission ROE Methodology

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 transmission owning subsidiaries on a prospective basis, and could affect future net income and cash flows and impact financial condition.

Impacts of Severe Winter Weather in February 2021

In February 2021, many of AEP's service territories and customers were impacted by severe winter weather and extreme cold temperatures resulting in power outages, extensive damage to transmission and distribution infrastructure and disruption to the energy markets.

Storm Costs

Based on the information currently available, APCo, KPCo and SWEPCo currently estimate significant February 2021 storm restoration expenditures as shown in the table below. Management currently anticipates the storm restoration expenditures will be more heavily weighted towards other operation and maintenance expenses as compared to capital expenditures. Management will continue to refine these storm cost estimates as restoration efforts are completed and final costs become available.

	Total Estimated February 2021 Storm Restoration Expenditures		
	(in millions)		
APCo	$65.0	-	$75.0
KPCo	$75.0	-	$95.0
SWEPCo	$30.0	-	$40.0

Management plans to seek regulatory recovery of these costs. If any of the storm costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

February 2021 Severe Winter Weather Impacts in SPP

The February 2021 severe winter weather also had a significant impact in SPP resulting in the declaration of Energy Emergency Alert Levels 2 and 3 for the first time in SPP's history. The winter storm increased the demand for natural gas and restricted the available natural gas supply resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. From February 9, 2021, to February 20, 2021, based on the information currently available, PSO's and SWEPCo's preliminary estimates of natural gas expenses and purchases of electricity are as follows:

	PSO	SWEPCo
	(in millions)	
Estimated Natural Gas Expenses	$ 175.0	$ 375.0
Estimated Electricity Purchases	650.0	—
	$ 825.0	$ 375.0

The amounts in the table above represent preliminary estimates as of February 25, 2021, and are subject to final settlement as additional information becomes available. In addition, SPP notified PSO and SWEPCo of additional collateral requirements of approximately $868 million on a cumulative basis for the companies due March 2, 2021. Subsequently, SPP filed a waiver request with the FERC that would grant a limited waiver for Load Serving Entities to post this additional collateral requirement between February 24, 2021 and March 11, 2021. FERC approved the waiver request on February 24, 2021.

PSO and SWEPCo have active fuel clauses that allow for the recovery of prudently incurred fuel and purchased power expenses. Given the significance of these costs, PSO and SWEPCo expect regulators to perform a heightened review of the costs. Management believes these costs are probable of future recovery. However, the recovery of these costs from customers may be extended over longer than usual time periods to mitigate the impact on customer bills. Nevertheless, PSO and SWEPCo's payments to suppliers are due in March 2021.

PSO and SWEPCo are evaluating financing alternatives including funding contributions from Parent and long-term debt issuances to address the timing difference between the payment to suppliers and recovery from customers. If either PSO or SWEPCo is unable to recover these fuel and purchased power expenses or recover these expenses in a timely manner, it could reduce future net income and cash flows and impact financial condition.

ERCOT

In response to the extreme winter weather event, the Governor of Texas issued a Declaration of a State of Disaster for all counties in Texas. While recovery from the emergency conditions is continuing, some market conditions and activities have yet to return to normal. To assist with a return to normalcy, the PUCT issued an order that placed a temporary moratorium on customer disconnections due to non-payment for transmission and distribution utilities. This moratorium will be in effect until otherwise ordered by the PUCT.

LITIGATION

In the ordinary course of business, AEP is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss if the loss can be estimated. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition. See Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies for additional information.

Rockport Plant Litigation

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

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

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

Thereafter, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree. The district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. The consent decree was modified based on an agreement among the parties in July 2019. The district court'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 to plaintiffs' motion for partial summary judgement was filed in October 2020. At the parties' request, the district court stayed the case until February 16, 2021 to provide the parties an opportunity to resolve the case, and the court has since extended the stay until April 26, 2021. See "Modification of the New Source Review Litigation Consent Decree" section below for additional information.

Management will continue to defend against the claims and believes its financial statements appropriately reflect the potential outcome of the pending litigation. The ultimate outcome of the pending litigation could reduce future net income and cash flows and impact financial condition.

Patent Infringement Complaint

In July 2019, Midwest Energy Emissions Corporation and MES Inc. (collectively, the plaintiffs) filed a patent infringement complaint against various parties, including AEP Texas, AGR, Cardinal Operating Company and SWEPCo (collectively, the AEP Defendants). The complaint alleges that the AEP Defendants infringed two patents owned by the plaintiffs by using specific processes for mercury control at certain coal-fired generating stations. The complaint was resolved in December 2020 and did not have a material impact on net income, cash flows or financial condition.

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 is 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. The company will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In January 2021, an AEP shareholder filed a derivative action in the United States District Court for the Southern District of Ohio purporting to assert claims on behalf of AEP against certain AEP officers and directors. In February 2021, a second AEP shareholder filed a similar derivative action in the Court of Common Pleas of Franklin County, Ohio. The derivative complaints allege the officers and directors made misrepresentations and omissions similar to those alleged in the putative securities class action lawsuit filed against AEP. The complaints assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets and (c) unjust enrichment and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The company will continue to defend against the claims. 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 December 31, 2020, the AEP System owned generating capacity of approximately 24,400 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 $350 million to $700 million through 2027.

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 2020. Construction 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 recently reviewed the existing standards for PM and ozone and in December 2020 announced both standards would be retained without change.

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, and that rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit as well as in the U.S. Court of Appeals for the District of Columbia Circuit. Management cannot predict the outcome of that litigation, although management supports the intrastate trading program as a compliance alternative to source-specific controls and has intervened in the litigation in support of the Federal EPA.

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.

In October 2020, the Federal EPA proposed a revised CSAPR Update rule, which would substantially reduce the ozone season NO_X budgets in 2021-2024. The Federal EPA recently released the underlying modeling and budget allocations and management is evaluating the potential impacts of this proposed rule.

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). Implementation of the CPP was stayed by the U.S. Supreme Court pending the outcome of legal challenges, and the CPP was ultimately repealed by the Federal EPA in 2019 and replaced with the Affordable Clean Energy (ACE) rule. ACE established a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. States were to submit their plans for implementing the ACE rule in 2022, and the Federal EPA would have had up to two years to review and approve a plan or disapprove it and adopt a federal plan. However, in January 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it to the Federal EPA. It is too soon to predict how the Federal EPA will respond to the court's remand.

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. That rule has not been finalized. Management continues to actively monitor these rulemaking activities.

While no federal regulatory requirements to reduce CO_2 emissions are in place, 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 February 2021, 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 an 80% reduction from 2000 CO_2 emission levels from AEP generating facilities by 2030; the long-term goal is net-zero CO_2 emissions from AEP generating facilities by 2050. AEP's total estimated CO_2 emissions in 2020 were approximately 44 million metric tons, a 73% 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. Technological advances, including energy storage, will determine how quickly AEP can achieve zero emissions while continuing to provide reliable, affordable power for customers.

Excessive costs to comply with future legislation or regulations has led to the announcement of early plant closures and could force AEP to close additional coal-fired generation facilities earlier than their estimate useful life. If AEP is unable to recover the costs of its investments, it would reduce future net income and cash flows and impact financial condition.

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, are the subject of further rulemaking that has not been finalized.

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. In December 2020, the Federal EPA issued draft guidance for public comment on applying the outcome of the Supreme Court's decision and consideration of functionally equivalent factors. 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 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. AEP filed applications for additional time to develop alternative disposal capacity at the following plants:

Company	Plant Name and Unit	Generating Capacity	Net Book Value (a)		Projected Retirement Date
		(in MWs)	(in millions)		
APCo	Amos	2,930	$ 2,171.8		2040
APCo	Mountaineer	1,320	980.2		2040
SWEPCo	Flint Creek Plant	258	279.2		2038
KPCo	Mitchell Plant	780	605.1		2040
WPCo	Mitchell Plant	780	603.7		2040
AEGCo	Rockport Plant, Unit 1	655	248.9		2028
I&M	Rockport Plant, Unit 1	655	573.8	(b)	2028

(a) Net book value before cost of removal including CWIP and inventory.
(b) Amount includes a $191 million regulatory asset related to the retired Tanners Creek Plant. The IURC and MPSC authorized recovery of the Tanners Creek Plant regulatory asset over the useful life of Rockport Plant, Unit 1 in 2015 and 2014, respectively.

In December 2020, APCo filed requests with the Virginia SCC and WVPSC to obtain the regulatory approvals necessary to implement the compliance plans and seek recovery of the estimated $240 million investment for the Amos and Mountaineer plants. In December 2020 and February 2021, WPCo and KPCo filed requests with the WVPSC and KPSC, respectively, to obtain the regulatory approvals necessary to implement the compliance plans and seek recovery of the estimated $132 million investment for the Mitchell Plant. Within those requests, WPCo and KPCo also filed a $25 million alternative with the WVPSC and KPSC, respectively, which would allow the Mitchell Plant to continue operating only through 2028.

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. Pursuant to this option, AEP informed the Federal EPA of its intent to retire the Pirkey Power Plant and cease using coal at the Welsh Plant:

Company	Plant Name and Unit	Generating Capacity	Net Investment (a)	Accelerated Depreciation Regulatory Asset	Projected Retirement Date
		(in MWs)	(in millions)		
SWEPCo	Pirkey Power Plant	580	$ 199.5	$ 12.2	2023 (b)
SWEPCo	Welsh Plants, Units 1 & 3	1,053	549.8	3.6	2028 (c)(d)

(a) Net book value including CWIP excluding cost of removal and materials and supplies.
(b) Pirkey Power Plant is currently being recovered through 2025 in the Louisiana jurisdiction and through 2045 in the Arkansas and Texas jurisdictions.
(c) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028.
(d) Unit 1 is currently being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Unit 3 is currently being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

AEP may incur significant costs to upgrade or close and replace surface impoundments and landfills used to manage CCR and to conduct any required remedial actions. 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 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. APCo will submit filings with the Virginia SCC and the WVPSC requesting recovery of the respective Virginia and West Virginia jurisdictional shares of these Glen Lyn Station ARO costs. As of December 31, 2020, APCo has not yet incurred any incremental costs associated with the removal of coal combustion material at the Glen Lyn Station.

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 have already 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 has assessed 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. Permit modifications for affected facilities were filed in January 2021 that reflect the outcome of that assessment.

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 (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, 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 narrowed the focus of NWP 12 to only oil and natural gas pipeline activities. The Corps proposed 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. In January 2021, the Corps issued 16 final Nationwide Permits, including NWP 12 and the two new utility line permits, NWP 57 and NWP 58. The Corps chose not to reissue or modify the remaining Nationwide Permits at this time. The 2017 versions of those permits remain in effect. Management is currently assessing impacts of the rulemaking on current and planned projects.

Impact of Environmental Regulation on Coal-Fired Generation

Compliance with extensive environmental regulations requires significant capital investment in environmental monitoring, installation of pollution control equipment, emission fees, disposal costs and permits. Management continuously evaluates cost estimates of complying with these regulations which may result in a decision to retire coal-fired generating facilities earlier than their currently estimated useful lives.

In addition to the November 2020 announcement related to the Federal EPA's CCR rules, management also decided not to renew the Rockport Plant, Unit 2 lease when it expires in 2022. Previously, management retired or announced early closure plans for Welsh Unit 2, Oklaunion Power Station, Dolet Hills Power Station and Northeastern Plant Unit 3.

The table below summarizes the net book value, as of December 31, 2020, of generating facilities retired or planned for early retirement:

Company	Plant	Net Investment (a)	Accelerated Depreciation Regulatory Asset	Actual/Projected Retirement Date	Current Authorized Recovery Period	Annual Depreciation (b)
		(in millions)				(in millions)
SWEPCo	Dolet Hills Power Station	$ 74.4	$ 71.2	2021	(c)	$ 60.8
PSO	Northeastern Plant, Unit 3	198.4	110.4	2026	(d)	14.9
PSO	Oklaunion Power Station	—	34.4	2020	(e)	—
SWEPCo	Pirkey Power Plant	199.5	12.2	2023	(f)	13.8
SWEPCo	Welsh Plant, Units 1 and 3	549.8	3.6	2028 (g)	(h)	33.3
SWEPCo	Welsh Plant, Unit 2	—	35.2	2016	(i)	—

(a) Net book value including CWIP excluding cost of removal and materials and supplies.
(b) These amounts represent the amount of annual depreciation that has been collected from customers over the prior 12-month period.
(c) Dolet Hills Power Station is current being recovered through 2026 in the Louisiana jurisdiction and through 2046 in the Arkansas and Texas jurisdictions.
(d) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(e) Oklaunion Power Station is currently being recovered through 2046.
(f) Pirkey Power Plant is currently being recovered through 2025 in the Louisiana jurisdiction and through 2045 in the Arkansas and Texas jurisdictions.
(g) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028.
(h) Welsh Plant, Unit 1 is being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Welsh Plant, Unit 3 is being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.
(i) Welsh Plant, Unit 2 is being recovered over the blended useful life of Welsh Plant, Units 1 and 3.

Management is seeking or will seek regulatory recovery, as necessary, for any net book value remaining when the plants are retired. To the extent the net book value of these generation assets are not deemed recoverable, it could materially reduce future net income, cash flows and impact financial condition.

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

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

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.

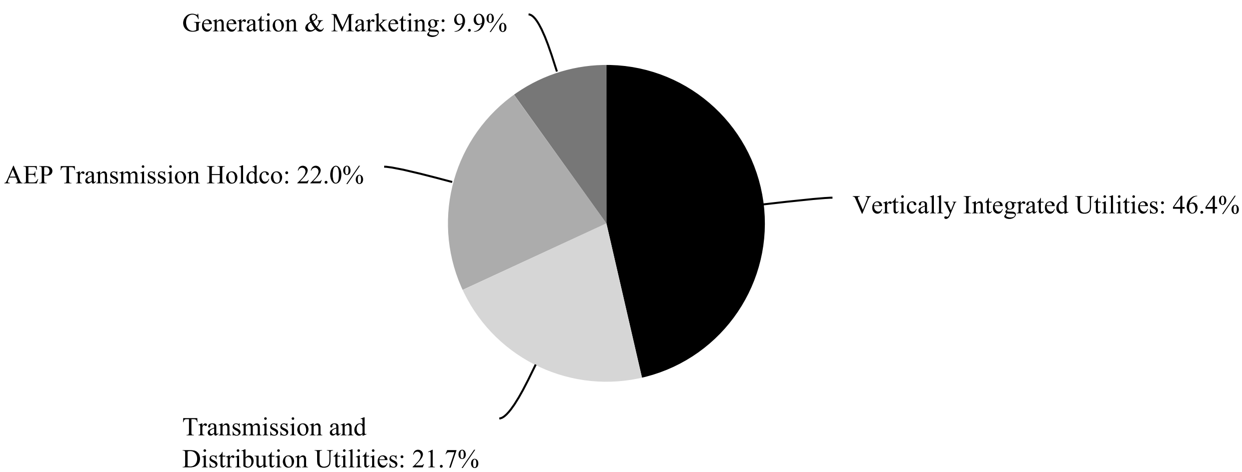
The following discussion of AEP's 2020 results of operations by operating segment includes an analysis of Gross Margin, which is a non-GAAP financial measure. Gross Margin includes Total Revenues less the costs of Fuel and Other Consumables Used for Electric Generation as well as Purchased Electricity 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.

A detailed discussion of AEP's 2019 results of operations by operating segment can be found in Management's Discussion and Analysis of Financial Condition and Results of Operation section included in the 2019 Annual Report on Form 10-K filed with the SEC on February 20, 2020.

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

	Years Ended December 31,		
	2020	**2019**	**2018**
		(in millions)	
Vertically Integrated Utilities	$ 1,061.6	$ 982.0	$ 990.5
Transmission and Distribution Utilities	496.4	451.0	527.4
AEP Transmission Holdco	504.8	516.3	369.9
Generation & Marketing	226.9	112.8	135.3
Corporate and Other	(89.6)	(141.0)	(99.3)
Earnings Attributable to AEP Common Shareholders	$ 2,200.1	$ 1,921.1	$ 1,923.8

2020 Earnings Attributable to AEP Common Shareholders by Segment



Note: 2020 Earnings Attributable to AEP Common Shareholders by Segment excludes Corporate and Other which is not considered a reportable segment.

AEP CONSOLIDATED

2020 Compared to 2019

Earnings Attributable to AEP Common Shareholders increased from $1.9 billion in 2019 to $2.2 billion in 2020 primarily due to:

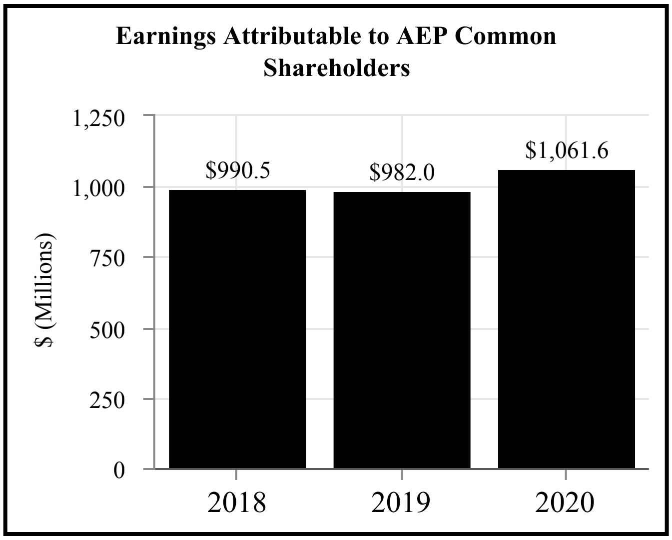
- Favorable rate proceedings in AEP's various jurisdictions.
- A planned decrease in Other Operation and Maintenance expenses.
- Continued transmission investment, which resulted in higher revenues and income.

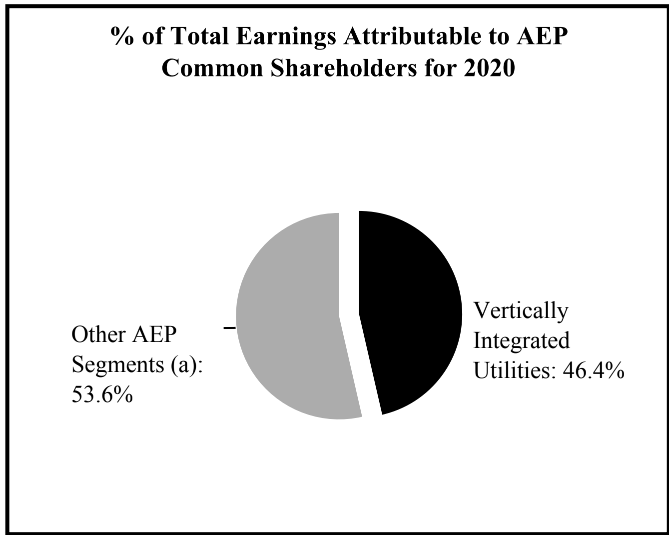
These increases were partially offset by:

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

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

VERTICALLY INTEGRATED UTILITIES





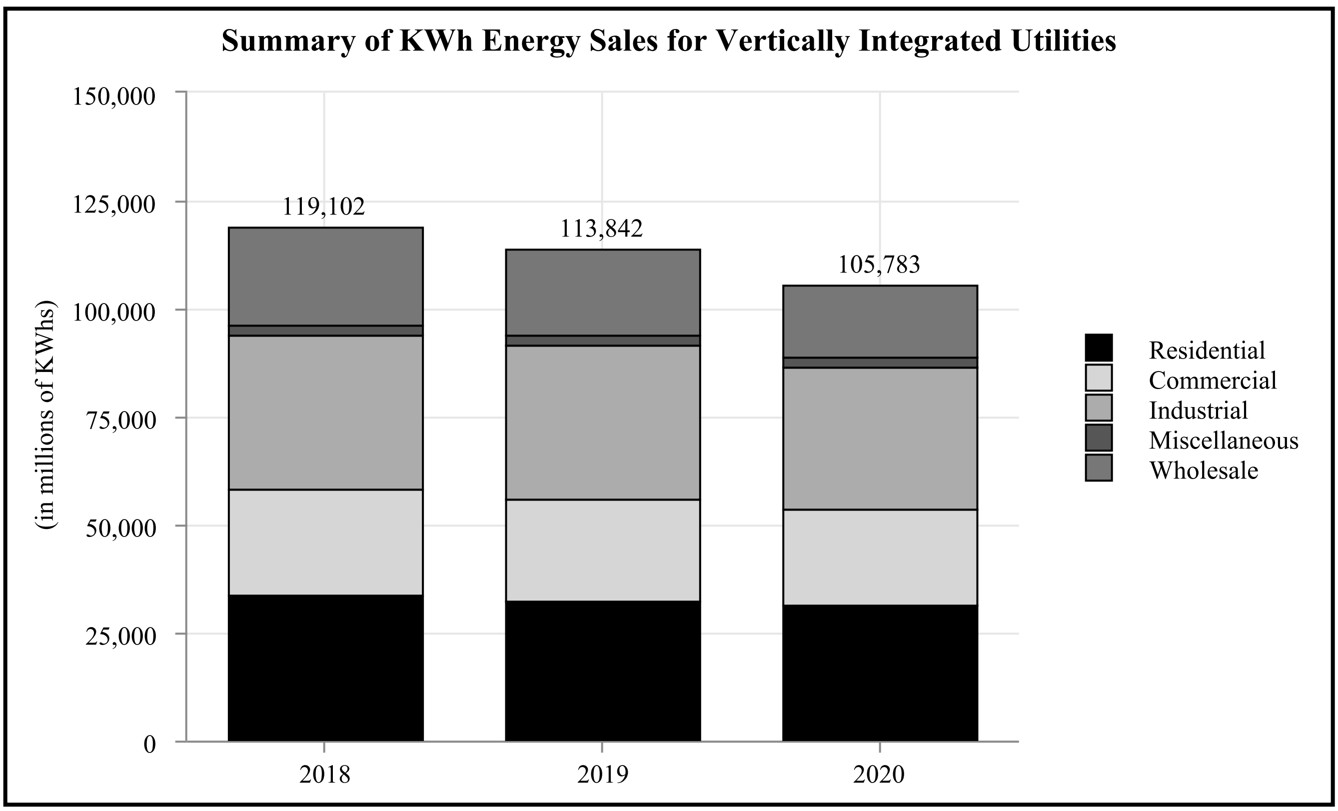
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Vertically Integrated Utilities	Years Ended December 31, 2020	2019	2018
		(in millions)	
Revenues	$ 8,879.4	$ 9,367.1	$ 9,645.5
Fuel and Purchased Electricity	2,544.9	3,103.1	3,488.9
Gross Margin	6,334.5	6,264.0	6,156.6
Other Operation and Maintenance	2,754.3	2,934.4	2,959.8
Asset Impairments and Other Related Charges	—	92.9	3.4
Depreciation and Amortization	1,600.5	1,447.0	1,316.2
Taxes Other Than Income Taxes	472.6	460.9	433.2
Operating Income	1,507.1	1,328.8	1,444.0
Other Income	2.4	6.1	17.0
Allowance for Equity Funds Used During Construction	42.2	50.7	35.4
Non-Service Cost Components of Net Periodic Benefit Cost	67.9	67.6	69.9
Interest Expense	(565.0)	(568.3)	(567.8)
Income Before Income Tax Expense (Benefit) and Equity Earnings	1,054.6	884.9	998.5
Income Tax Expense (Benefit)	(7.0)	(97.7)	5.7
Equity Earnings of Unconsolidated Subsidiary	2.9	3.0	2.7
Net Income	1,064.5	985.6	995.5
Net Income Attributable to Noncontrolling Interests	2.9	3.6	5.0
Earnings Attributable to AEP Common Shareholders	$ 1,061.6	$ 982.0	$ 990.5

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31,		
	2020	2019	2018
	(in millions of KWhs)		
Retail:			
Residential	31,526	32,359	33,908
Commercial	22,225	23,839	24,452
Industrial	32,860	35,252	35,730
Miscellaneous	2,185	2,302	2,330
Total Retail	88,796	93,752	96,420
Wholesale (a)	16,987	20,090	22,682
Total KWhs	105,783	113,842	119,102

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

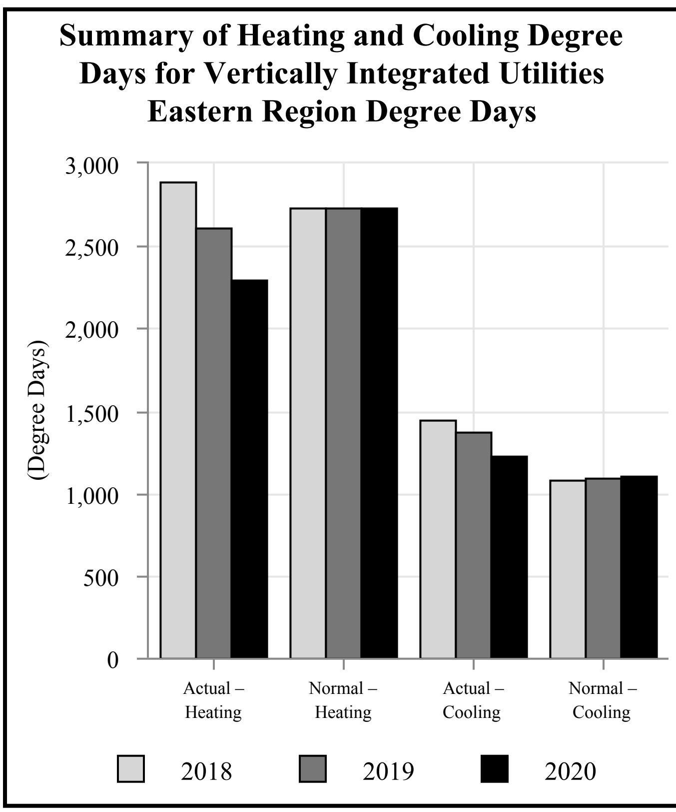


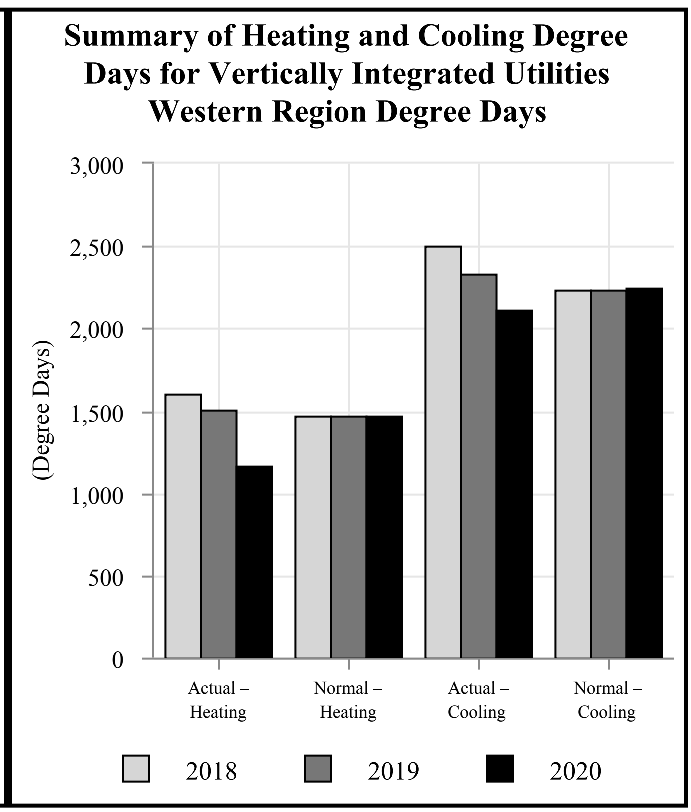
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31, 2020	2019	2018
		(in degree days)	
Eastern Region			
Actual – Heating (a)	2,295	2,617	2,886
Normal – Heating (b)	2,727	2,732	2,738
Actual – Cooling (c)	1,222	1,369	1,443
Normal – Cooling (b)	1,104	1,092	1,083
Western Region			
Actual – Heating (a)	1,160	1,512	1,599
Normal – Heating (b)	1,464	1,473	1,475
Actual – Cooling (c)	2,117	2,328	2,502
Normal – Cooling (b)	2,253	2,240	2,230

(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.





2020 Compared to 2019

Reconciliation of Year Ended December 31, 2019 to Year Ended December 31, 2020
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2019	$ 982.0
Changes in Gross Margin:	
Retail Margins	30.7
Margins from Off-system Sales	(12.5)
Transmission Revenues	60.3
Other Revenues	(8.0)
Total Change in Gross Margin	70.5
Changes in Expenses and Other:	
Other Operation and Maintenance	180.1
Asset Impairments and Other Related Charges	92.9
Depreciation and Amortization	(153.5)
Taxes Other Than Income Taxes	(11.7)
Other Income	(3.7)
Allowance for Equity Funds Used During Construction	(8.5)
Non-Service Cost Components of Net Periodic Pension Cost	0.3
Interest Expense	3.3
Total Change in Expenses and Other	99.2
Income Tax Expense	(90.7)
Equity Earnings of Unconsolidated Subsidiary	(0.1)
Net Income Attributable to Noncontrolling Interests	0.7
Year Ended December 31, 2020	$ 1,061.6

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 $31 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 $20 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 $17 million increase due to a decrease in customer refunds related to Tax Reform. This increase was partially offset 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.
  - A $10 million increase at APCo and WPCo due to revenue from rate riders primarily in West Virginia. This increase was partially offset in other expense items below.
  - A $9 million increase due to an environmental expense deferral at APCo.
  - An $8 million increase in weather-normalized retail margins driven by a $111 million increase in the residential customer class partially offset by a $97 million decrease in the commercial and industrial classes.

- The effect of rate proceedings in AEP's service territories which included:
  - A $109 million increase at I&M 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.
  - A $45 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.
  - An $8 million increase at APCo and WPCo due to new base rates implemented in 2019 in West Virginia. This increase was partially offset in Depreciation and Amortization expenses below.

  These increases were partially offset by:
- A $128 million decrease in weather-related usage primarily in the eastern region and primarily in the residential class.
- A $66 million decrease in weather-normalized margins for wholesale contracts, including the loss of a significant wholesale contract at I&M.
- A $44 million decrease due to the cumulative impact of the implementation of APCo's 2017 and 2019 generation and distribution depreciation studies as ordered in the Virginia triennial base rate case.
- A $13 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 $13 million due to weaker market prices for energy in the RTOs which caused a decrease in sales margins and volume. In addition, the historical merchant portion of WPCo's Mitchell Plant moved to retail rates beginning in January 2020.
- **Transmission Revenues** increased $60 million primarily due to the following:
  - A $31 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.
  - A $22 million increase due to continued investment in transmission projects primarily at SWEPCo.
  - A $12 million increase at APCo resulting from the 2017-2019 Virginia triennial base rate case. This increase was offset in Depreciation Expense below.
- **Other Revenues** decreased $8 million primarily due to the following:
  - A $10 million decrease at I&M primarily due to a decrease in barging revenues by River Transportation Division. This decrease was partially offset in Other Operation and Maintenance expenses below.
  - An $8 million decrease primarily due to suspension of late fees and disconnections in 2020 as a result of the COVID-19 pandemic.

  These decreases were partially offset by:
  - A $9 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 $180 million primarily due to the following:
  - A $49 million decrease due to the re-establishment of a regulatory asset in 2020 as result of APCo's 2017-2019 Virginia triennial review which authorized the recovery of previously retired coal-fired generation assets.
  - A $47 million decrease in plant outage and maintenance expenses primarily at APCo, I&M, WPCo, KPCo and PSO.
  - A $34 million decrease in charitable contributions primarily driven by the contribution to the AEP Foundation in 2019.
  - A $32 million decrease in distribution expenses primarily related to vegetation management and other distribution expenses.
  - A $28 million decrease in transmission expenses primarily related to accelerated vegetation management and maintenance in 2019.
  - A $15 million decrease due to the capitalization of previously expensed North Central Wind Energy Facilities costs at SWEPCo and PSO.
  - A $14 million decrease related to a 2020 insurance settlement primarily at SWEPCo and PSO.
  - An $8 million decrease due to the modification of the NSR consent decree impacting I&M and AEGCo in 2019.

- A $7 million decrease at I&M due to an increased Nuclear Electric Insurance Limited distribution in 2020.

These decreases were partially offset by:

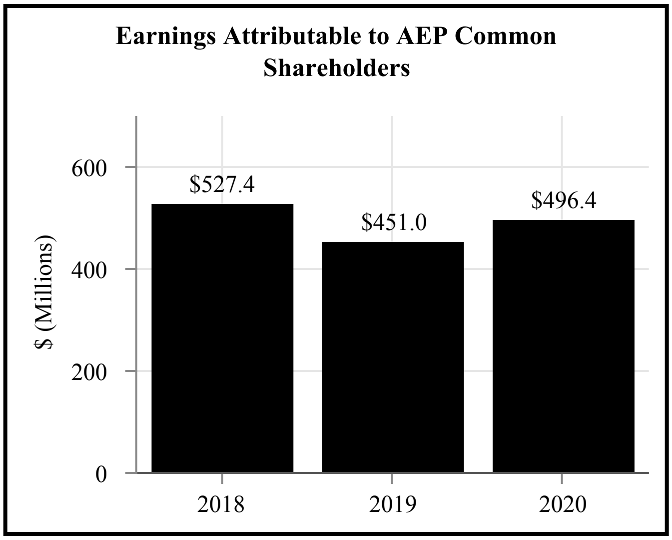
- A $39 million increase due to SPP transmission services including the annual formula rate true-up.
- A $37 million increase in employee-related expenses.

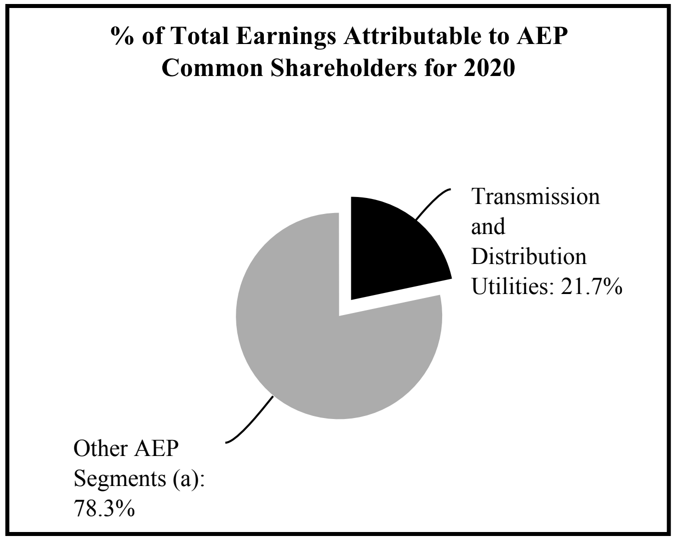
- **Asset Impairments and Other Related Charges** decreased $93 million primarily due to a pretax expense recorded in 2019 related to previously retired coal-fired assets.
- **Depreciation and Amortization** expenses increased $154 million primarily due to a higher depreciable base and increased depreciation rates approved at I&M, APCo and SWEPCo. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $12 million primarily due to increased property taxes primarily at APCo, I&M, PSO and SWEPCo.
- **Other Income** decreased $4 million primarily due to a decrease in affiliated interest income due to a decrease in interest rates in 2020.
- **Allowance for Equity Funds Used During Construction** decreased $9 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** decreased $3 million primarily due to the following:
  - A $10 million decrease primarily due to lower interest rates on long-term debt primarily at PSO and AEGCo.
  - A $6 million decrease primarily due to lower interest rates on variable rate loans and carrying charges recorded on various riders at I&M. This decrease was partially offset by a decrease in AFUDC base.

  These decreases were partially offset by:

  - A $13 million increase primarily due to higher long-term debt balances at APCo.
- **Income Tax Expense** increased $91 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 not subject to normalization requirements is partially offset above in Gross Margin and Other Operation and Maintenance expenses.

TRANSMISSION AND DISTRIBUTION UTILITIES





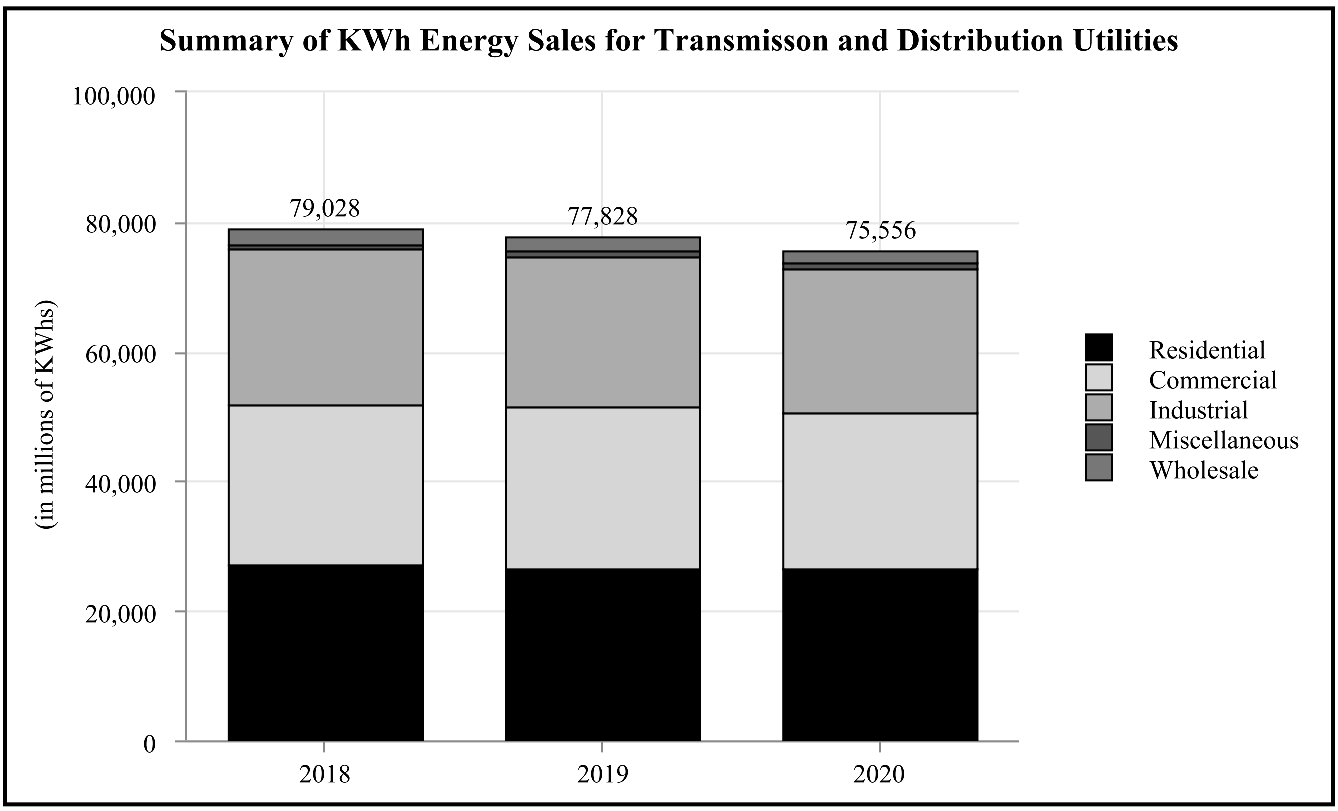
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Transmission and Distribution Utilities	Years Ended December 31, 2020	2019	2018
		(in millions)	
Revenues	$ 4,345.9	$ 4,482.5	$ 4,653.1
Purchased Electricity	682.7	794.3	858.3
Amortization of Generation Deferrals	—	65.3	223.9
Gross Margin	3,663.2	3,622.9	3,570.9
Other Operation and Maintenance	1,575.4	1,628.1	1,541.7
Asset Impairments and Other Related Charges	—	32.5	—
Depreciation and Amortization	751.1	789.5	734.1
Taxes Other Than Income Taxes	586.7	575.0	545.3
Operating Income	750.0	597.8	749.8
Interest and Investment Income	2.4	6.6	4.2
Carrying Costs Income	1.6	1.0	1.7
Allowance for Equity Funds Used During Construction	31.9	33.4	29.9
Non-Service Cost Components of Net Periodic Benefit Cost	29.4	30.3	32.3
Interest Expense	(289.2)	(243.3)	(248.1)
Income Before Income Tax Expense (Benefit)	526.1	425.8	569.8
Income Tax Expense (Benefit)	29.7	(25.2)	42.4
Net Income	496.4	451.0	527.4
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 496.4	$ 451.0	$ 527.4

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31,		
	2020	2019	2018
	(in millions of KWhs)		
Retail:			
Residential	26,518	26,407	27,042
Commercial	23,998	25,018	24,877
Industrial	22,432	23,289	23,908
Miscellaneous	749	779	760
Total Retail (a)	73,697	75,493	76,587
Wholesale (b)	1,859	2,335	2,441
Total KWhs	75,556	77,828	79,028

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

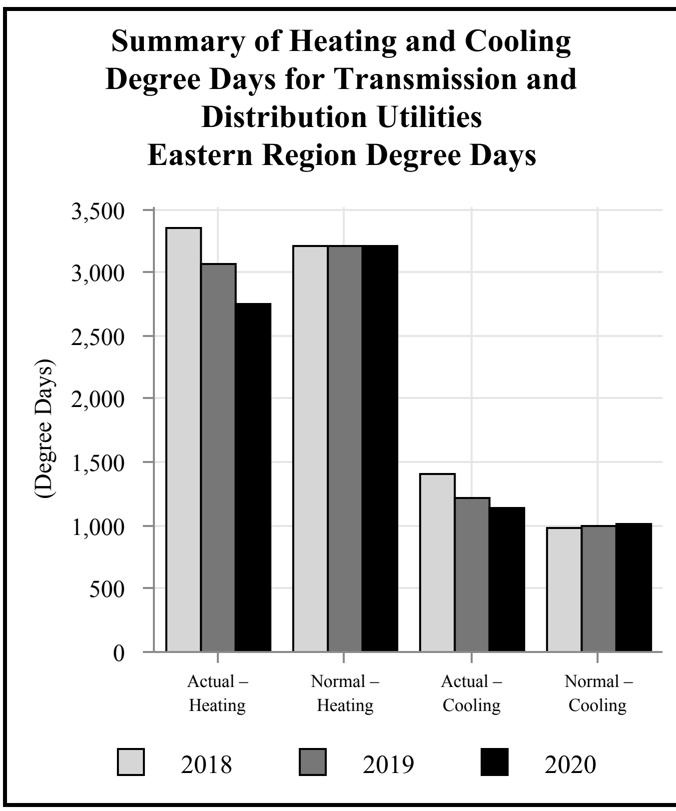


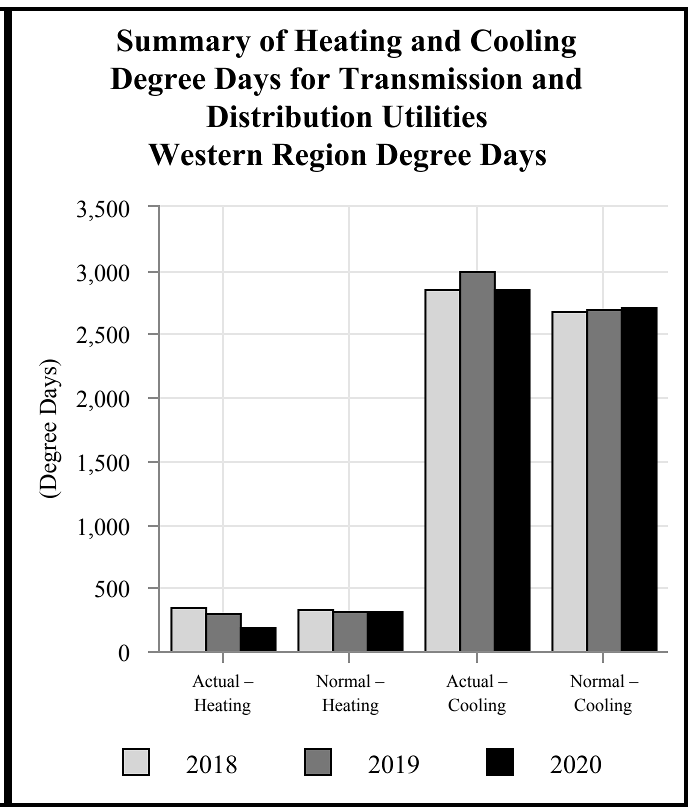
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two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

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

	Years Ended December 31,		
	2020	**2019**	**2018**
		(in degree days)	
<u>Eastern Region</u>			
Actual – Heating (a)	2,743	3,071	3,357
Normal – Heating (b)	3,202	3,208	3,215
Actual – Cooling (c)	1,140	1,224	1,402
Normal – Cooling (b)	1,006	992	980
<u>Western Region</u>			
Actual – Heating (a)	189	301	354
Normal – Heating (b)	313	322	325
Actual – Cooling (d)	2,846	2,989	2,861
Normal – Cooling (b)	2,711	2,699	2,688

(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.





2020 Compared to 2019

Reconciliation of Year Ended December 31, 2019 to Year Ended December 31, 2020
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2019	$	451.0
Changes in Gross Margin:		
Retail Margins		90.4
Margins from Off-system Sales		(39.3)
Transmission Revenues		44.2
Other Revenues		(55.0)
Total Change in Gross Margin		40.3
Changes in Expenses and Other:		
Other Operation and Maintenance		52.7
Asset Impairments and Other Related Charges		32.5
Depreciation and Amortization		38.4
Taxes Other Than Income Taxes		(11.7)
Interest and Investment Income		(4.2)
Carrying Costs Income		0.6
Allowance for Equity Funds Used During Construction		(1.5)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.9)
Interest Expense		(45.9)
Total Change in Expenses and Other		60.0
Income Tax Expense		(54.9)
Year Ended December 31, 2020	$	496.4

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 $90 million primarily due to the following:
  - A $69 million net increase related to other various rider revenues in Ohio. This increase was partially offset in other expense items below.
  - A $61 million increase in rider revenues in Ohio associated with the DIR. This increase was partially offset in other expense items below.
  - A $30 million increase due to a provision for refund recorded in December 2019 as part of the 2019 Texas base rate case.
  - A $16 million increase from interim rate increases driven by increased distribution investment in Texas.
  - A $13 million increase due to new base rates implemented in June 2020 in Texas.
  - A $12 million increase from interim rate increases driven by increased transmission investment in Texas.
  - A $9 million increase in weather-normalized margins primarily in the residential class and partially offset in the industrial and commercial classes.
  - A $6 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.
  - 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 $38 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 $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 $17 million decrease in weather-related usage in Texas primarily due to a 5% decrease in cooling degree days.
  - A $6 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 $39 million primarily due to the following:
  - A $52 million decrease in Texas due to lower Oklaunion Power Station PPA revenues. This decrease was offset in Other Operation and Maintenance expenses below.
  - A $17 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:
  - A $26 million increase in Ohio due to higher OVEC PPA deferrals. This increase was offset in Retail Margins above.
- **Transmission Revenues** increased $44 million primarily due to the following:
  - A $48 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 $12 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 $55 million primarily due to the following:
  - A $96 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 $19 million increase in Ohio primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs. This increase was offset in Retail Margins above.
  - An $18 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 $53 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.
  - An $18 million decrease in distribution expenses primarily due to vegetation management. This decrease was partially offset in Retail Margins above.
  - 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.
  - A $16 million decrease in affiliated PPA expenses in Texas. This decrease was offset in Margins from Off-system Sales above.
  - A $12 million decrease due to a charitable contribution to the AEP Foundation in 2019.
  - A $7 million decrease in customer-related expenses.
  - 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.

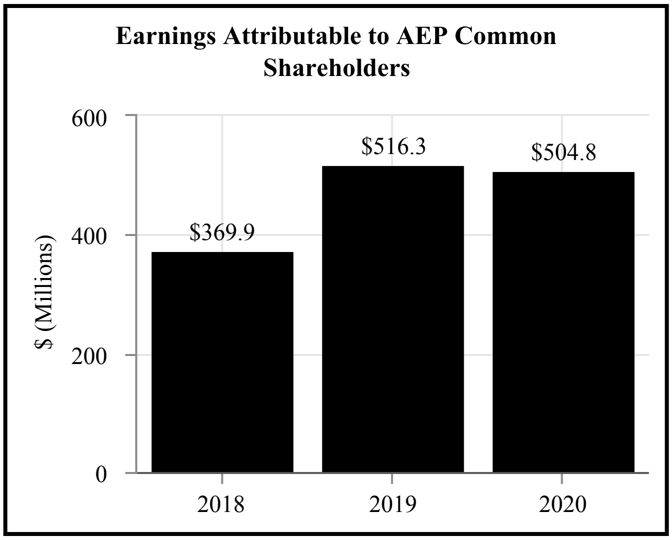
  These decreases were partially offset by:
  - A $62 million net increase in PJM transmission expenses, primarily due to a $94 million increase in recoverable expenses, partially offset by a $28 million decrease related to the annual transmission formula rate true-up. This increase was offset in Gross Margin above.

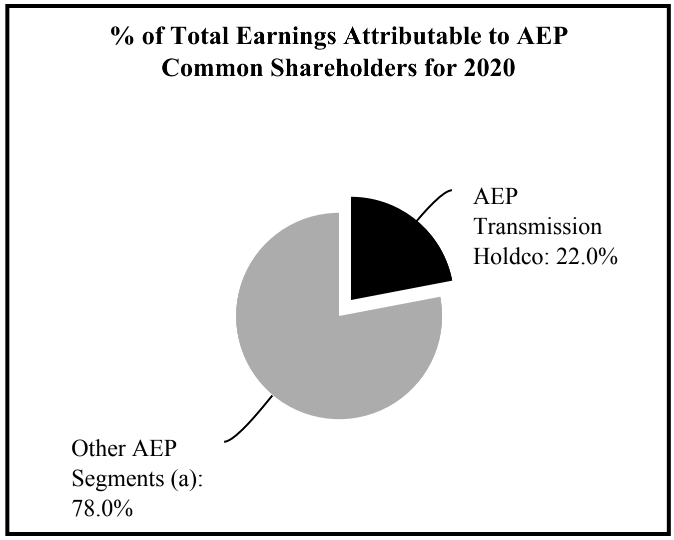
    - A $19 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.
    - A $17 million increase in ERCOT transmission expenses. This increase was partially offset in Gross Margin above.
- **Asset Impairments and Other Related Charges** decreased $33 million due to prior year regulatory disallowances in the 2019 Texas Base Rate Case.
- **Depreciation and Amortization** expenses decreased $38 million primarily due to the following:
    - An $87 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 $31 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
    - A $22 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 $6 million increase due to prior year under-recovery of revenues in Ohio associated with the Deferred Asset Phase-In-Recovery securitization which ended in the 2nd quarter of 2019. This decrease was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $12 million primarily due to the following:
    - A $19 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 $6 million decrease in excise taxes due to lower demand in 2020 in Ohio. This decrease was offset in Retail Margins above.
- **Interest Expense** increased $46 million primarily due to the following:
    - A $32 million increase due to higher long-term debt balances.
    - A $22 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.
    - An $8 million increase due to due to a decrease in the debt component of AFUDC.

  These increases were partially offset by:
    - An $8 million decrease in expense related to securitization assets. This decrease was offset above in Other Revenues and Depreciation and Amortization expenses.
    - A $6 million decrease due to lower short-term debt balances.
- **Income Tax Expense** increased $55 million primarily due to an increase in pretax book income and a decrease in Excess ADIT not subject to normalization requirements as approved in the Texas Storm Cost Securitization financing order issued by the PUCT in 2019. The decrease in Excess ADIT not subject to normalization requirements was partially offset in Gross Margins and Other Operation and Maintenance Expenses above.



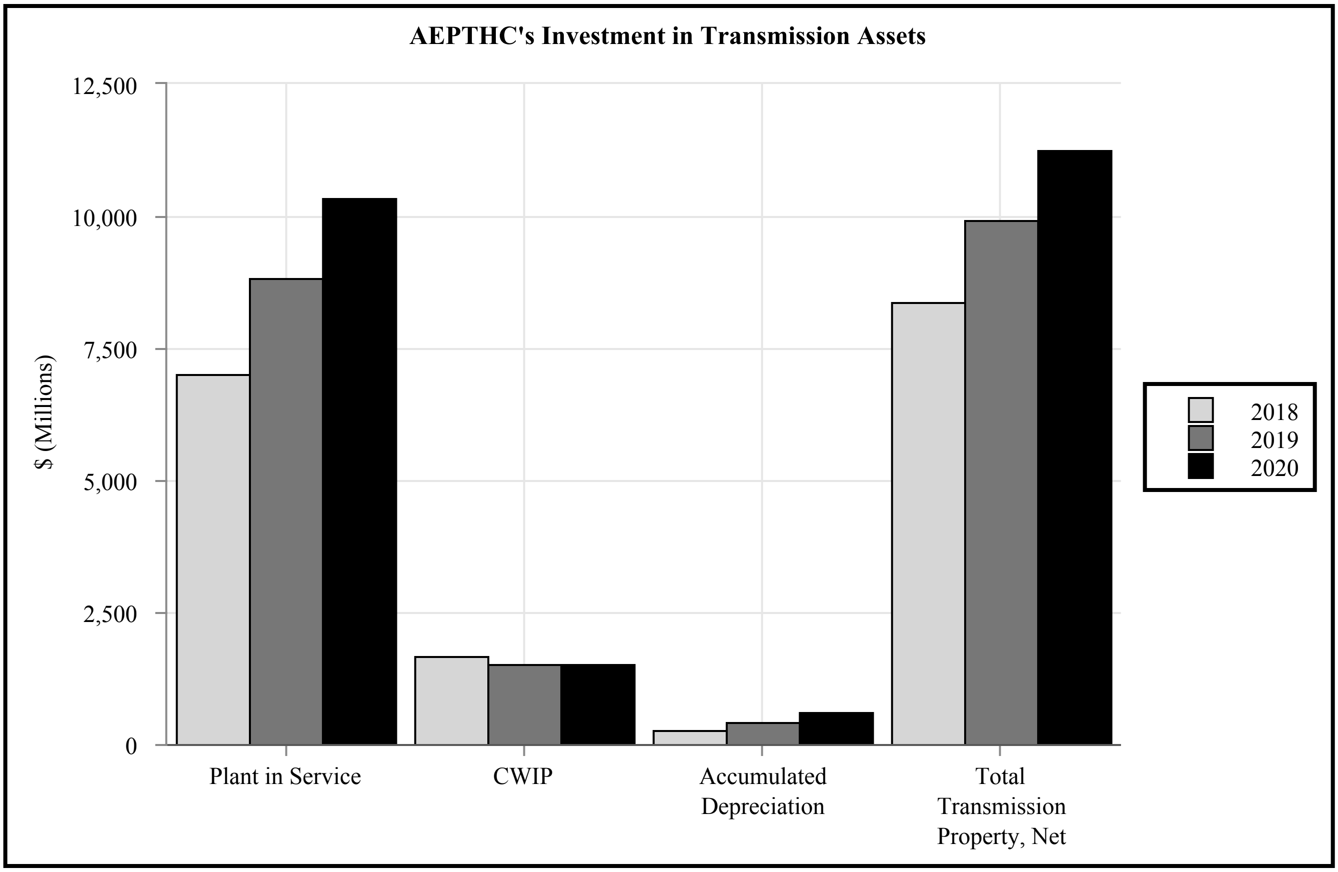


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

AEP Transmission Holdco	Years Ended December 31, 2020	2019	2018
		(in millions)	
Transmission Revenues	$ 1,198.8	$ 1,073.2	$ 804.1
Other Operation and Maintenance	119.0	119.0	105.6
Depreciation and Amortization	257.6	183.4	137.8
Taxes Other Than Income Taxes	211.0	174.4	142.3
Operating Income	611.2	596.4	418.4
Interest and Investment Income	2.9	3.4	2.1
Allowance for Equity Funds Used During Construction	74.0	84.3	67.2
Non-Service Cost Components of Net Periodic Benefit Cost	2.0	2.7	2.6
Interest Expense	(133.2)	(103.3)	(90.7)
Income Before Income Tax Expense and Equity Earnings	556.9	583.5	399.6
Income Tax Expense	130.8	136.2	95.3
Equity Earnings of Unconsolidated Subsidiary	82.4	72.8	68.7
Net Income	508.5	520.1	373.0
Net Income Attributable to Noncontrolling Interests	3.7	3.8	3.1
Earnings Attributable to AEP Common Shareholders	$ 504.8	$ 516.3	$ 369.9

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	2020	December 31, 2019	2018
		(in millions)	
Plant in Service	$ 10,327.5	$ 8,812.2	$ 7,008.4
Construction Work in Progress	1,499.7	1,521.8	1,651.1
Accumulated Depreciation and Amortization	595.7	418.9	282.8
Total Transmission Property, Net	$ 11,231.5	$ 9,915.1	$ 8,376.7



2020 Compared to 2019

Reconciliation of Year Ended December 31, 2019 to Year Ended December 31, 2020
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2019	$	516.3
Changes in Transmission Revenues:		
Transmission Revenues		125.6
Total Change in Transmission Revenues		125.6
Changes in Expenses and Other:		
Depreciation and Amortization		(74.2)
Taxes Other Than Income Taxes		(36.6)
Other Income		(0.5)
Allowance for Equity Funds Used During Construction		(10.3)
Non-Service Cost Components of Net Periodic Pension Cost		(0.7)
Interest Expense		(29.9)
Total Change in Expenses and Other		(152.2)
Income Tax Expense		5.4
Equity Earnings of Unconsolidated Subsidiary		9.6
Net Income Attributable to Noncontrolling Interests		0.1
Year Ended December 31, 2020	$	504.8

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

- **Transmission Revenues** increased $126 million primarily due to the following:
  - A $208 million increase due to continued investment in transmission assets.

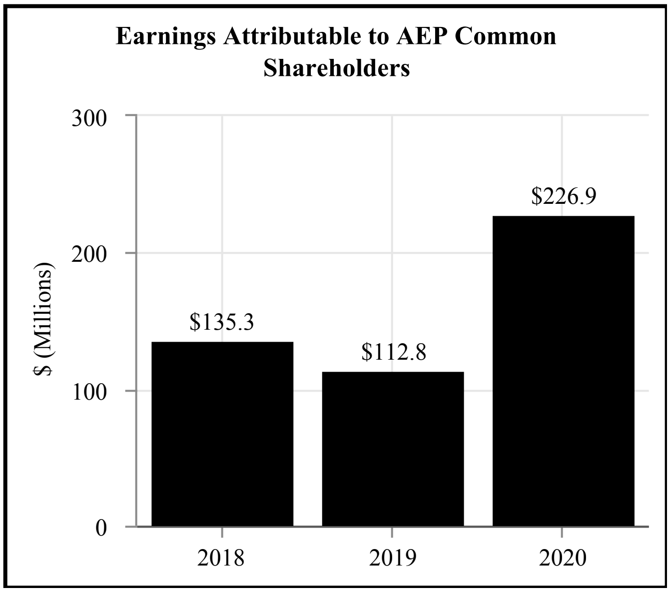
  This increase was partially offset by the following:
  - A $65 million decrease as a result of the affiliated annual transmission formula rate true-up which is offset in Other Operation and Maintenance expense across affiliated load-serving entities.
  - A $17 million decrease as a result of the nonaffiliated annual transmission formula rate true-up.

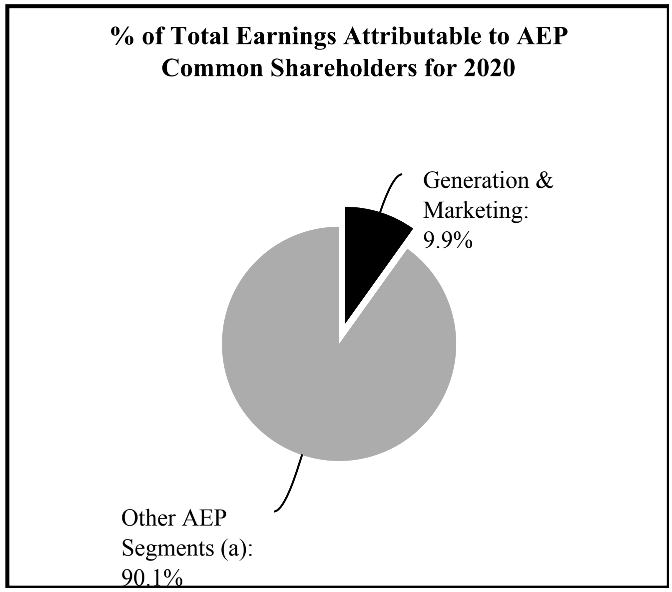
Expenses and Other, Income Tax Expense and Equity Earnings of Unconsolidated Subsidiary changed between years as follows:

- **Depreciation and Amortization** expenses increased $74 million primarily due to a higher depreciable base and an increase in depreciation rates as a result of regulatory orders in 2020 in Indiana, Virginia and Michigan.
- **Taxes Other Than Income Taxes** increased $37 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** decreased $10 million primarily due to the following:
  - A $13 million decrease due to lower CWIP.
  - A $12 million decrease driven by the favorable impact of a FERC settlement agreement recorded in 2019.

  These decreases were partially offset by:
  - A $13 million increase driven by FERC audit findings recorded in 2019.
- **Interest Expense** increased $30 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $5 million primarily due to lower pretax book income and an increase in amortization of Excess ADIT.
- **Equity Earnings of Unconsolidated Subsidiary** increased $10 million primarily due to higher pretax equity earnings at PATH-WV and ETT.

GENERATION & MARKETING



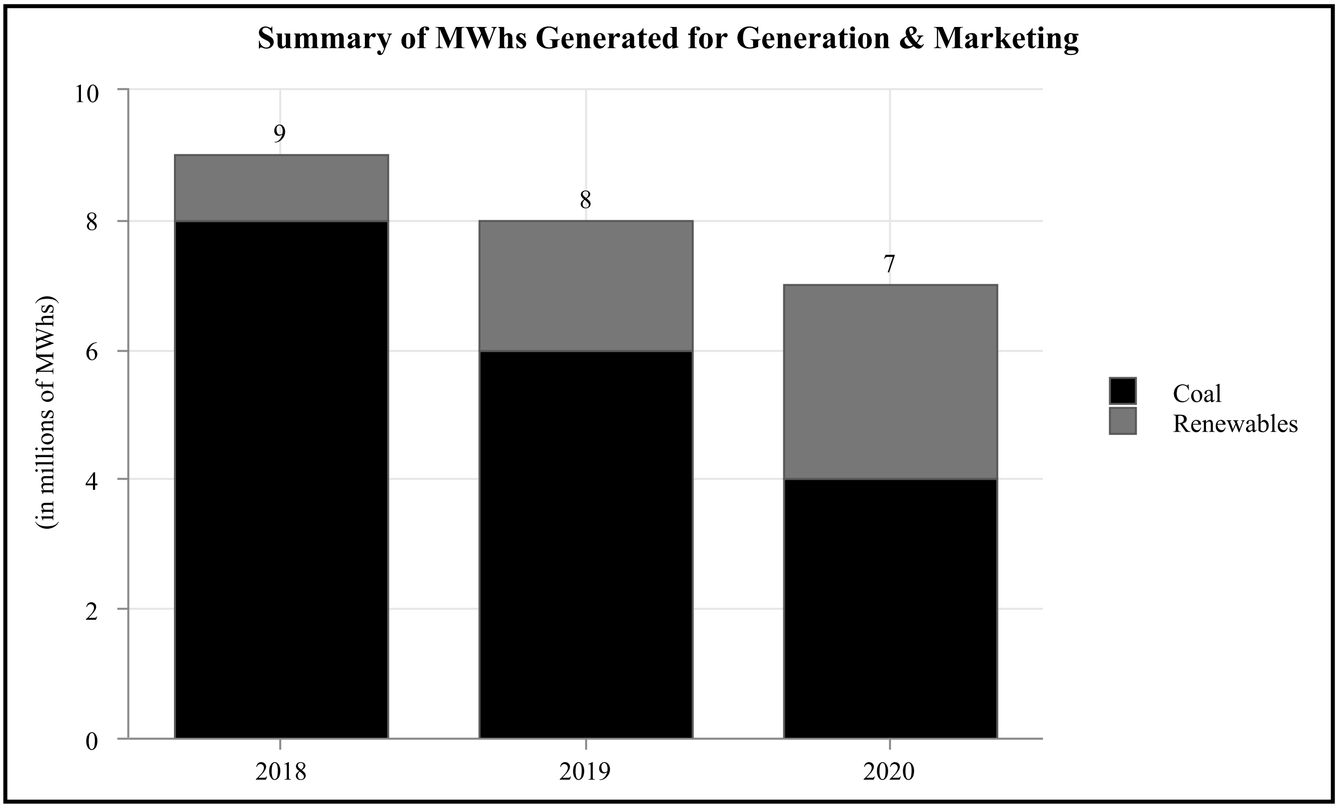


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Generation & Marketing	Years Ended December 31, 2020	2019	2018
		(in millions)	
Revenues	$ 1,725.6	$ 1,857.6	$ 1,940.3
Fuel, Purchased Electricity and Other	1,403.6	1,456.2	1,537.3
Gross Margin	322.0	401.4	403.0
Other Operation and Maintenance	124.9	223.8	229.3
Asset Impairments and Other Related Charges	—	31.0	47.7
Depreciation and Amortization	72.8	69.5	41.0
Taxes Other Than Income Taxes	13.2	15.6	13.4
Operating Income	111.1	61.5	71.6
Interest and Investment Income	3.2	7.7	13.1
Non-Service Cost Components of Net Periodic Benefit Cost	15.4	14.9	15.2
Interest Expense	(24.0)	(30.0)	(14.9)
Income Before Income Tax Benefit and Equity Earnings (Loss)	105.7	54.1	85.0
Income Tax Benefit	(108.0)	(53.8)	(49.2)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	3.2	(3.8)	0.5
Net Income	216.9	104.1	134.7
Net Loss Attributable to Noncontrolling Interests	(10.0)	(8.7)	(0.6)
Earnings Attributable to AEP Common Shareholders	$ 226.9	$ 112.8	$ 135.3

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31, 2020	2019	2018
	(in millions of MWhs)		
Fuel Type:			
Coal	4	6	8
Renewables	3	2	1
Total MWhs	7	8	9



2020 Compared to 2019

Reconciliation of Year Ended December 31, 2019 to Year Ended December 31, 2020
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2019	$	112.8
Changes in Gross Margin:		
Merchant Generation		(78.2)
Renewable Generation		9.7
Retail, Trading and Marketing		(10.9)
Total Change in Gross Margin		(79.4)
Changes in Expenses and Other:		
Other Operation and Maintenance		98.9
Asset Impairments and Other Related Charges		31.0
Depreciation and Amortization		(3.3)
Taxes Other Than Income Taxes		2.4
Interest and Investment Income		(4.5)
Non-Service Cost Components of Net Periodic Benefit Cost		0.5
Interest Expense		6.0
Total Change in Expenses and Other		131.0
Income Tax Benefit		54.2
Equity Earnings of Unconsolidated Subsidiaries		7.0
Net Loss Attributable to Noncontrolling Interests		1.3
Year Ended December 31, 2020	$	226.9

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, Unit 4 in 2020 and the Oklaunion Power Station in 2020.
- **Renewable Generation** increased $10 million primarily due to the Sempra Renewables LLC acquisition and other renewable projects placed in-service.
- **Retail, Trading and Marketing** decreased $11 million primarily due to lower retail margins.

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

- **Other Operation and Maintenance** expenses decreased $99 million primarily due to following:
  - A $36 million decrease due to the retirements of Conesville Plant Units 5 and 6 in 2019 and Unit 4 in 2020.
  - A $34 million decrease due to a gain recorded on the sale of land.
  - An $18 million decrease related to the Oklaunion PPA with AEP Texas primarily due to an ARO revision.
  - An $11 million decrease primarily in employee expenses due to the sale of the Stuart Plant in 2019.
- **Asset Impairments and Other Related Charges** decreased $31 million primarily due to impairment charges related to the Conesville Plant in 2019.
- **Depreciation and Amortization** expenses increased $3 million primarily due to a higher depreciable base from increased investments in renewable energy sources.

- **Interest and Investment Income** decreased $5 million due to lower returns on investments.
- **Interest Expense** decreased $6 million primarily due lower borrowing costs in 2020.
- **Income Tax Benefit** increased $54 million primarily due to the realization of tax benefit related to the 5-year NOL carryback provision of the CARES Act and an increase in PTCs. This decrease was partially offset by an increase in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiaries** increased $7 million primarily due to the Sempra Renewables LLC acquisition.

CORPORATE AND OTHER

2020 Compared to 2019

Earnings attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $141 million in 2019 to a loss of $90 million in 2020 primarily due to:

- A $32 million decrease in tax expense primarily due to the following:
  - A $21 million decrease in state income tax expense related to unitary state filing requirements.
  - A $5 million decrease in permanent tax expense.
  - A $3 million decrease due to a favorable true-up related to the 2019 federal income tax return.
  - A $2 million decrease due to the realization of tax benefit related to the 5-year NOL carryback provision of the CARES Act.
- A $32 million gain on the valuation of common share warrants for an interest in a privately held investee.
- A $5 million write-off of an equity investment and related assets in 2019.

These items were partially offset by:

- A $12 million decrease in interest income from affiliates.
- A $7 million increase in general corporate expenses.

AEP SYSTEM INCOME TAXES

2020 Compared to 2019

Income Tax Expense increased $53 million primarily due to a decrease in amortization of Excess ADIT and an increase in pretax book income. This increase is partially offset by the recognition of tax benefit related to the 5-year NOL carryback provision as a result of the CARES Act, an increase in PTCs and a decrease in state tax expense.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2020		2019	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 31,072.5	57.2 %	$ 26,725.5	54.1 %
Short-term Debt	2,479.3	4.6	2,838.3	5.7
Total Debt	33,551.8	61.8	29,563.8	59.8
AEP Common Equity	20,550.9	37.8	19,632.2	39.6
Noncontrolling Interests	223.6	0.4	281.0	0.6
Total Debt and Equity Capitalization	$ 54,326.3	100.0 %	$ 49,477.0	100.0 %

AEP's ratio of debt-to-total capital increased from 59.8% to 61.8% as of December 31, 2019 and 2020, respectively, primarily due to an increase in debt to support distribution, transmission and renewable investment growth.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of December 31, 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. In November 2020, AEP repaid the 364-day Term Loan.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of December 31, 2020, available liquidity was approximately $2.5 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 4,000.0	June 2022
Cash and Cash Equivalents	392.7	
Total Liquidity Sources	4,392.7	
Less: AEP Commercial Paper Outstanding	1,852.3	
Net Available Liquidity	$ 2,540.4	

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 2020 was $3 billion. The weighted-average interest rate for AEP's commercial paper during 2020 was 1.28%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $405 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2020, was $180 million with maturities ranging from January 2021 to December 2021.

Financing Plan

As of December 31, 2020, AEP had $2.1 billion of long-term debt due within one year. This included $235 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current and $190 million of securitization bonds and DCC Fuel notes. Management plans to refinance the majority of the maturities due within one year on a long-term basis.

Securitized Accounts Receivables

AEP receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in 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 December 31, 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, the affiliated utility subsidiary would no longer participate in the receivables securitization agreement and the Registrants would need to rely on additional sources of funding for operation and working capital, which may adversely impact liquidity. The receivables that are ineligible under the receivables securitization agreement are financed with short-term debt at AEP Credit.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreement excludes securitization bonds and debt of AEP Credit. As of December 31, 2020, this contractually-defined percentage was 58.6%. 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 recent acquisition of Sempra Renewables LLC.

See Note 14 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.74 per-share in January 2021. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends. Management does not believe these restrictions will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 14 for additional information.

Credit Ratings

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

CASH FLOW

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

	Years Ended December 31,		
	2020	**2019**	**2018**
		(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 432.6	$ 444.1	$ 412.6
Net Cash Flows from Operating Activities	3,832.9	4,270.1	5,223.2
Net Cash Flows Used for Investing Activities	(6,233.9)	(7,144.5)	(6,353.6)
Net Cash Flows from Financing Activities	2,406.7	2,862.9	1,161.9
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	5.7	(11.5)	31.5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 438.3	$ 432.6	$ 444.1

Operating Activities

	Years Ended December 31,		
	2020	2019	2018
		(in millions)	
Net Income	$ 2,196.7	$ 1,919.8	$ 1,931.3
Non-Cash Adjustments to Net Income (a)	2,946.3	2,685.7	2,400.0
Mark-to-Market of Risk Management Contracts	66.5	(29.2)	(66.4)
Pension Contributions to Qualified Plan Trust	(110.3)	—	—
Property Taxes	(43.3)	(73.8)	(59.1)
Deferred Fuel Over/Under Recovery, Net	(31.8)	85.2	189.7
Change in Regulatory Assets	(337.9)	49.5	354.1
Change in Other Noncurrent Assets	(142.5)	(112.8)	(172.1)
Change in Other Noncurrent Liabilities	(54.5)	(116.1)	129.0
Change in Certain Components of Working Capital	(656.3)	(138.2)	516.7
Net Cash Flows from Operating Activities	$ 3,832.9	$ 4,270.1	$ 5,223.2

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Rockport Plant Unit 2 Operating Lease Amortization, Deferred Income Taxes, Asset Impairments and Other Related Charges, Allowance for Equity Funds Used During Construction, Amortization of Nuclear Fuel and Pension and Postemployment Benefit Reserves.

2020 Compared to 2019

Net Cash Flows from Operating Activities decreased by $437 million primarily due to the following:

- A $518 million decrease in cash from Changes in Certain Components of Working Capital. This decrease is primarily due to an increase in accounts receivable driven by increased sales in December 2020 and increased days sales outstanding.
- A $387 million decrease in cash from Changes in Regulatory Assets primarily due to deferred storm costs related to Hurricanes Laura and Delta, the establishment of regulatory assets as a result of the Virginia SCC order issued in the 2017-2019 Virginia Triennial Review and the settlement of deferred restoration costs from the Texas Storm Cost Securitization financing order received in 2019. See Note 4 - Rate Matters and Note 5 - Effects of Regulation for additional information.
- A $117 million decrease in cash from Deferred Fuel Over/Under Recovery, Net primarily due to an increase in the under recovered fuel balances at PSO.
- A $110 million decrease in cash due to a discretionary contribution to the qualified pension plan. See Note 8 - Benefit Plans for additional information.

These decreases in cash were partially offset by:

- A $538 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.
- A $96 million increase in the fair value of risk management contracts due to pricing movement in the commodities markets.

Investing Activities

	Years Ended December 31,		
	2020	2019	2018
		(in millions)	
Construction Expenditures	$ (6,246.3)	$ (6,051.4)	$ (6,310.9)
Acquisitions of Nuclear Fuel	(69.7)	(92.3)	(46.1)
Acquisition of Sempra Renewables LLC and Santa Rita East, net of cash and restricted cash acquired	—	(918.4)	—
Other	82.1	(82.4)	3.4
Net Cash Flows Used for Investing Activities	$ (6,233.9)	$ (7,144.5)	$ (6,353.6)

2020 Compared to 2019

Net Cash Flows Used for Investing Activities decreased by $911 million primarily due to the following:

- A $918 million decrease due to the acquisition of Sempra Renewables LLC and Santa Rita East. The $918 million represents a cash payment of $936 million, net of cash and restricted cash acquired of $18 million. See Note 7 - Acquisitions, Dispositions and Impairments for additional information.

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

- A $195 million increase in construction expenditures primarily due to increases in Transmission Operations of $190 million and Generation & Marketing of $110 million, partially offset by a decrease in Vertically Integrated of $146 million.

Financing Activities

	Years Ended December 31,		
	2020	2019	2018
		(in millions)	
Issuance of Common Stock	$ 155.0	$ 65.3	$ 73.6
Issuance/Retirement of Debt, Net	3,927.3	4,244.1	2,435.1
Dividends Paid on Common Stock	(1,424.9)	(1,350.0)	(1,255.5)
Redemption of Noncontrolling Interests	(100.2)	—	—
Other	(150.5)	(96.5)	(91.3)
Net Cash Flows from Financing Activities	$ 2,406.7	$ 2,862.9	$ 1,161.9

2020 Compared to 2019

Net Cash Flows from Financing Activities decreased by $456 million primarily due to the following:

- A $1.3 billion decrease in short-term debt primarily due to increased repayments of commercial paper. See Note 14 - Financing Activities for additional information.
- A $119 million decrease due to increased retirements of long-term debt. See Note 14 - Financing Activities for additional information.
- A $100 million decrease due to the redemption of noncontrolling interests in Desert Sky Wind Farm LLC and Trent Wind Farm LLC as well as the acquisition of an additional 10% interest in Santa Rita East. See Note 7 - Acquisitions, Dispositions and Impairments for additional information.

These decreases in cash were partially offset by:

- A $1.1 billion increase in issuances of long-term debt. See Note 14 - Financing Activities for additional information.

The following financing activities occurred during 2020:

AEP Common Stock:

- During 2020, AEP issued 2.4 million shares of common stock under the incentive compensation, employee saving and dividend reinvestment plans and received net proceeds of $155 million.

Debt:

- During 2020, AEP issued approximately $5.6 billion of long-term debt, including $4.4 billion of senior unsecured notes at interest rates ranging from 0.75% to 3.7%, $850 million of junior subordinated debenture notes at an interest rate of 1.3%, $175 million of pollution control bonds at interest rates ranging from 0.625% to 1.00%, and $238 million of other debt at various interest rates. The proceeds from these issuances were used to fund long-term debt maturities and construction programs.
- During 2020, AEP entered into interest rate derivatives with notional amounts totaling $1.8 billion that were designated as either fair value or cash flow hedges. During 2020, settlements of AEP's interest rate derivatives resulted in net cash received of $59 million for derivatives designated as fair value hedges and net cash paid of $38 million for derivatives designated as cash flow hedges. As of December 31, 2020, AEP had a total notional amount of $950 million of outstanding interest rate derivatives designated as fair value hedges and $200 million designated as cash flow hedges.

See "Long-term Debt Subsequent Events" section of Note 14 for Long-term debt and other securities issued, retired and principal payments made after December 31, 2020 through February 25, 2021, the date that the 10-K was issued.

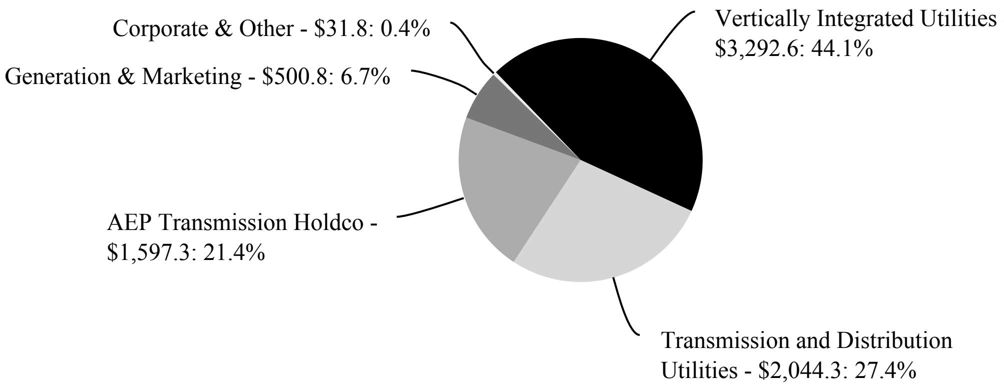
BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $7.5 billion of capital expenditures in 2021. For the four year period, 2022 through 2025, management forecasts capital expenditures of $29.8 billion. The expenditures are generally for transmission, generation, distribution, regulated and contracted renewables, and required environmental investment to comply with the Federal EPA rules. Estimated capital expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. Management expects to fund these capital expenditures through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2021 estimated capital expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2021 Budgeted Capital Expenditures						
Segment	**Environmental**	**Generation**	**Renewables**	**Transmission**	**Distribution**	**Other (a)**	**Total**
				(in millions)			
Vertically Integrated Utilities	$ 124.7	$ 264.7	$ 711.3	$ 787.1	$ 1,040.5	$ 364.3	$ 3,292.6
Transmission and Distribution Utilities	—	—	—	833.9	977.3	233.1	2,044.3
AEP Transmission Holdco	—	—	—	1,564.5	—	32.8	1,597.3
Generation & Marketing	9.1	39.9	434.1	—	—	17.7	500.8
Corporate and Other	—	—	—	—	—	31.8	31.8
Total	$ 133.8	$ 304.6	$ 1,145.4	$ 3,185.5	$ 2,017.8	$ 679.7	$ 7,466.8

(a) Amount primarily consists of facilities, software and telecommunications.

2021 Budgeted Capital Expenditures by Business Segment
($ in millions)

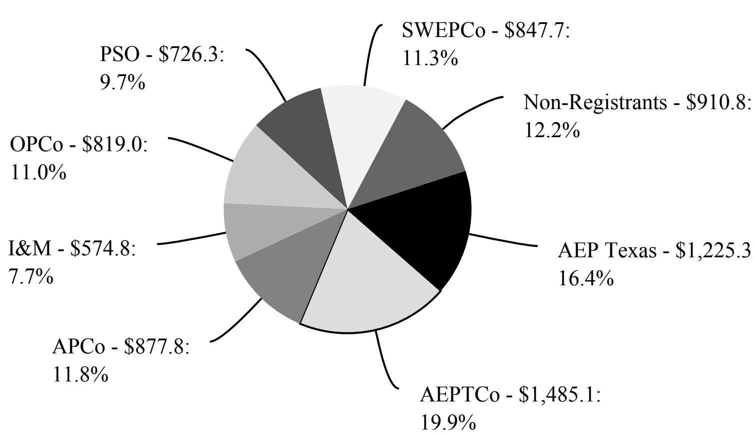


The 2021 estimated capital expenditures by Registrant Subsidiary include distribution, transmission and generation-related investments, as well as expenditures for compliance with environmental regulations as follows:

	2021 Budgeted Capital Expenditures						
Company	Environmental	Generation	Renewables	Transmission	Distribution	Other (a)	Total
				(in millions)			
AEP Texas	$ —	$ —	$ —	$ 606.8	$ 513.7	$ 104.8	$ 1,225.3
AEPTCo	—	—	—	1,451.7	—	33.4	1,485.1
APCo	60.6	64.1	1.0	309.6	341.8	100.7	877.8
I&M	16.8	75.9	1.3	98.3	268.1	114.4	574.8
OPCo	—	—	—	227.1	463.6	128.3	819.0
PSO	—	42.5	322.3	102.3	210.7	48.5	726.3
SWEPCo	8.8	43.9	386.7	205.4	135.8	67.1	847.7

(a) Amount primarily consists of facilities, software and telecommunications.

2021 Budgeted Capital Expenditures by Registrant Subsidiary
($ in millions)



CYBER SECURITY

The electric utility industry is an identified critical infrastructure function with mandatory cyber security requirements under the authority of FERC. The NERC, which FERC certified as the nation's Electric Reliability Organization, developed mandatory critical infrastructure protection cyber security reliability standards. AEP's service territory covers multiple NERC regions, and is audited at least annually by one or more of the regions. AEP began participating in the NERC grid security and emergency response exercises, GridEx, in 2013 and continues to participate in the bi-yearly exercises. These efforts, led by NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid. The operations of AEP's electric utility subsidiaries are subject to extensive and rigorous mandatory cyber and physical security requirements that are developed and enforced by NERC to protect grid security and reliability. AEP's Enterprise Security program uses the National Institute of Standards and Technology Cybersecurity Framework as a guideline. AEP's Chief Security Officer (CSO) is also its NERC Critical Infrastructure Protection Senior Manager, ensuring alignment of compliance with the enterprise security program.

Critical cyber assets, such as data centers, power plants, transmission operations centers and business networks are protected using multiple layers of cyber security controls and authentication. Cyber hackers have been successful in breaching a number of very secure facilities, including federal agencies, banks and retailers. As understanding of these events develop, AEP has adopted a defense in depth approach to cyber security and continually assesses its cyber security tools and processes to determine where to strengthen its defenses. These strategies include monitoring, alerting and emergency response, forensic analysis, disaster recovery, threat sharing and criminal activity reporting. This approach has allowed AEP to deal with threats in real-time and to limit the impact of cyber and related events to levels that would be expected in the ordinary course of business in the absence of such activity.

AEP has undertaken a variety of actions to monitor and address cyber-related risks. Cyber security and the effectiveness of AEP's cyber security processes are reviewed annually with the Board of Directors and at several meetings with the Audit Committee throughout the year. AEP's Chief Executive Officer and Executive team participate in interactive threat briefings from AEP's CSO and cyber security team on a monthly basis. AEP's strategy for managing cyber-related risks is integrated within its enterprise risk management processes. AEP enterprise security continually adjusts staff and resources in response to the evolving threat landscape. In addition, AEP maintains cyber liability insurance to cover certain damages caused by cyber incidents.

AEP's CSO leads the cyber security and physical security teams and is responsible for the design, implementation and execution of AEP's security risk management strategy, which includes cyber security. AEP's cyber security team operates a 24/7 Cyber Security Intelligence and Response Center responsible for monitoring the AEP System for cyber risks and threats. Under the direction of the CSO, the cyber security team actively monitors best practices, performs penetration testing, leads response exercises and internal campaigns and provides training and communication across the organization.

The cyber security team constantly scans the AEP System for risks and threats. AEP also continually reviews its business continuity plan to develop an effective recovery strategy that seeks to decrease response times, limit financial impacts and maintain customer confidence during any business interruption. AEP has implemented a third-party risk governance program to identify potential risks introduced through third-party relationships, such as vendors, software and hardware manufacturers or professional service providers. As warranted, AEP obtains certain contractual security guarantees and assurances with these third-party relationships to help ensure the security and safety of its information. The cyber security team works closely with a broad range of departments, including legal, regulatory, corporate communications and audit services and information technology.

The cyber security team collaborates with partners from both industry and government, and routinely participates in industry-wide programs that exchange knowledge of threats with utility peers, industry and federal agencies. AEP is an active member of a number of industry specific threat and information sharing communities including the Department of Homeland Security and the Electricity Information Sharing and Analysis Center. AEP continues to work with nonaffiliated entities to do penetration testing and to design and implement appropriate remediation strategies. There can be no assurance, however, that these efforts will be effective to prevent interruption of services or other damages to AEP's business or operations in connection with any cyber-related incident.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

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

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

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

Regulatory Accounting

Nature of Estimates Required

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

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

Assumptions and Approach Used

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

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. See Note 5 - Effects of Regulation for additional information related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

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

Accrued unbilled revenues for the Vertically Integrated Utilities segment were $288 million and $248 million as of December 31, 2020 and 2019, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $40 million, $(7) million and $(23) million for the years ended December 31, 2020, 2019 and 2018, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $171 million and $166 million as of December 31, 2020 and 2019, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $5 million, $(12) million and $(24) million for the years ended December 31, 2020, 2019 and 2018, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Generation & Marketing segment were $86 million and $75 million as of December 31, 2020 and 2019, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $11 million, $16 million and $5 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Assumptions and Approach Used

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

For AEP's Generation & Marketing segment, management calculates unbilled based on a primary computation of load as provided by PJM less the current month's billed KWh and estimated line losses, plus the prior month's unbilled KWh. However, due to the potential for meter reading issues, meter drift and other anomalies, a secondary computation is made, based upon using the most recent historic daily activity on a per contract basis. The two methodologies are evaluated to confirm that they are not statistically different.

Effect if Different Assumptions Used

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

Accounting for Derivative Instruments

Nature of Estimates Required

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

Assumptions and Approach Used

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

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

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

Effect if Different Assumptions Used

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

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

For additional information see Note 10 - Derivatives and Hedging and Note 11 - Fair Value Measurements. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for AEP's fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance and "Regulated Operations" accounting guidance, the Registrants evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. Such events or changes in circumstance include planned abandonments, probable disallowances for rate-making purposes of assets determined to be recently completed plant, and assets that meet the held-for-sale criteria. The Registrants utilize a group composite method of depreciation to estimate the useful lives of long-lived assets.

An impairment evaluation of a long-lived, held and used asset may result from an abandonment, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount of the asset is not recoverable, the Registrants record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the non-discounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. Assets held for sale must be measured at the lower of the book value or fair value less cost to sell. An impairment is recognized if an asset's fair value less costs to sell is less than its book value. Any impairment charge is recorded as a reduction to earnings.

Assumptions and Approach Used

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

Effect if Different Assumptions Used

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

Pension and OPEB

AEP maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, non-qualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Pension Plans and OPEB plans are collectively referred to as the Plans.

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

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

	Years Ended December 31,		
Net Periodic Cost (Credit)	**2020**	**2019**	**2018**
		(in millions)	
Pension Plans	$ 108.6	$ 61.5	$ 82.9
OPEB	(109.7)	(80.7)	(101.8)

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2021, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets and tax rates which affect a portion of the OPEB plans' assets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 4.75% for the Qualified Plan and 4.75% for the OPEB plans.

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

	Pension Plans		OPEB	
	2021 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2021 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	25 %	6.79 %	49 %	6.45 %
Fixed Income	59	3.30	49	3.18
Other Investments	15	7.88	—	—
Cash and Cash Equivalents	1	1.21	2	1.21
Total	100 %		100 %	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 4.75% for the Qualified Plan and 4.75% for the OPEB plans are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 16.91% and 15.81% for the year ended December 31, 2020 and 2019, respectively. The OPEB plans' assets had an actual gain of 16.33% and 20.93% for the year ended December 31, 2020 and 2019, respectively. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2020, AEP had cumulative gains of approximately $575 million for the Qualified Plan that remain to be recognized in the calculation of the market-related value of assets. These unrecognized market-related net actuarial gains may result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2020 under this method was 2.5% for the Qualified Plan, 2.25% for the Nonqualified Plans and 2.55% for the OPEB plans. Due to the effect of the unrecognized net actuarial losses and based on an expected rate of return on the Pension Plans' assets of 4.75%, discount rates of 2.5% and 2.25% and various other assumptions, management estimates that the pension costs for the Pension Plans will approximate $137 million, $137 million and $137 million in 2021, 2022 and 2023, respectively. Based on an expected rate of return on the OPEB plans' assets of 4.75%, a discount rate of 2.55% and various other assumptions, management estimates OPEB plan credits will approximate $121 million, $120 million and $112 million in 2021, 2022 and 2023, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of AEP's Pension Plans' assets increased to $5.6 billion as of December 31, 2020 from $5.0 billion as of December 31, 2019 primarily due to higher investment returns. During 2020, the Qualified Plan paid $402 million and the Nonqualified Plans paid $5 million in benefits to plan participants. The value of AEP's OPEB plans' assets increased to $1.9 billion as of December 31, 2020 from $1.8 billion as of December 31, 2019 primarily due to higher investment returns. The OPEB plans paid $131 million in benefits to plan participants during 2020.

Nature of Estimates Required

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

Assumptions and Approach Used

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

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

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

Effect if Different Assumptions Used

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

	Pension Plans		OPEB	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2020 Benefit Obligations				
Discount Rate	$ (286.9)	$ 316.2	$ (66.6)	$ 73.7
Compensation Increase Rate	32.9	(30.3)	NA	NA
Cash Balance Crediting Rate	81.2	(75.4)	NA	NA
Health Care Cost Trend Rate	NA	NA	12.7	(11.7)
Effect on 2020 Periodic Cost				
Discount Rate	$ (12.5)	$ 13.6	$ (3.2)	$ 3.4
Compensation Increase Rate	6.5	(5.9)	NA	NA
Cash Balance Crediting Rate	14.1	(13.2)	NA	NA
Health Care Cost Trend Rate	NA	NA	0.9	(0.8)
Expected Return on Plan Assets	(23.0)	23.0	(8.7)	8.7

NA Not applicable.

CONTRACTUAL OBLIGATION INFORMATION

AEP's contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in the footnotes. The following table summarizes AEP's contractual cash obligations as of December 31, 2020:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 2,479.3	$ —	$ —	$ —	$ 2,479.3
Interest on Fixed Rate Portion of Long-term Debt (b)	1,310.7	2,373.0	2,209.0	14,918.9	20,811.6
Fixed Rate Portion of Long-term Debt (c)	1,533.1	4,481.8	2,443.1	20,599.2	29,057.2
Variable Rate Portion of Long-term Debt (d)	553.0	1,715.9	6.6	—	2,275.5
Finance Lease Obligations (e)	72.2	120.2	96.2	48.9	337.5
Operating Lease Obligations (e)	270.8	357.5	149.6	193.0	970.9
Fuel Purchase Contracts (f)	763.9	715.1	212.9	381.5	2,073.4
Energy and Capacity Purchase Contracts	211.6	291.8	277.0	928.5	1,708.9
Construction Contracts for Capital Assets (g)	1,624.2	3,211.8	2,347.4	4,379.1	11,562.5
Total	$ 8,818.8	$ 13,267.1	$ 7,741.8	$ 41,449.1	$ 71,276.8

(a) Represents principal only, excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2020 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14 for additional information. Represents principal only, excluding interest.
(d) See "Long-term Debt" section of Note 14 for additional information. Represents principal only, excluding interest. Variable rate debt had interest rates that ranged between 0.18% and 2.25% as of December 31, 2020.
(e) See Note 13 - Leases for additional information.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

AEP's pension funding requirements are not included in the above table. As of December 31, 2020, AEP expects to make contributions to the pension plans totaling $133 million in 2021. Estimated contributions of $135 million in 2022 and $136 million in 2023 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, the pension plans were 100.2% funded as of December 31, 2020. See "Estimated Future Benefit Payments and Contributions" section of Note 8 for additional information.

In addition to the amounts disclosed in the contractual cash obligations table above, standby letters of credit are entered into with third-parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. There is no collateral held in relation to any guarantees in excess of the ownership percentages. In the event any letters of credit are drawn, there is no recourse to third-parties. See "Letters of Credit" section of Note 6 for additional information.

SIGNIFICANT TAX LEGISLATION

In March 2020, the CARES Act was signed into law and includes tax relief provisions such as: (a) an AMT Credit Refund, (b) a 5-year NOL carryback from years 2018-2020 and (c) delayed payment of employer payroll taxes. See "Federal Tax Legislation" section of Note 12 for additional information.

In December 2020, the CAA of 2021 was signed into law and includes: (a) COVID-19 tax relief and tax extender provisions including, extensions of time to begin construction on and placed in-service assets generating PTCs and ITCs, (b) 100% deductibility of business meals in 2021 and 2022 and (c) an extension of the work opportunity tax credit. See "Federal Tax Legislation" section of Note 12 for additional information.

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 basis. Markets 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. 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)
Year Ended December 31, 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	(44.3)	(7.2)	(17.9)	(69.4)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	15.2	15.2
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	7.4	7.4
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	9.6	1.3	—	10.9
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2020	$ 41.2	$ (109.5)	$ 168.1	99.8
Commodity Cash Flow Hedge Contracts				(75.4)
Interest Rate Cash Flow Hedge Contracts				(1.0)
Fair Value Hedge Contracts				(1.5)
Collateral Deposits				3.4
Total MTM Derivative Contract Net Assets as of December 31, 2020				$ 25.3

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

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

Credit Risk

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

AEP has risk management contracts (includes non-derivative contracts) with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of December 31, 2020, credit exposure net of collateral to sub investment grade counterparties was approximately 6.6%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 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	$ 412.2	$ —	$ 412.2	2	$ 198.2
Split Rating	1.1	—	1.1	1	1.1
No External Ratings:					
Internal Investment Grade	133.8	—	133.8	3	91.8
Internal Noninvestment Grade	49.4	10.5	38.9	2	25.6
Total as of December 31, 2020	$ 596.5	$ 10.5	$ 586.0		

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 December 31, 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

Twelve Months Ended December 31, 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

Twelve Months Ended December 31, 2020				Twelve Months Ended December 31, 2019			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 2.2	$ 2.9	$ 1.0	$ 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 12 months ended December 31, 2020, 2019 and 2018, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $32 million, $24 million and $25 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries (the "Company") as of December 31, 2020 and 2019, and the related consolidated statements of income, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2020, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for the Effects of Cost-Based Regulation

As described in Notes 1 and 5 to the consolidated financial statements, the Company's consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and matching income with its passage to customers in cost-based regulated rates. Management reviews the probability of recovery of regulatory assets and refund of regulatory liabilities at each balance sheet date and whenever new events occur, whether influenced by issuance of regulatory commission orders, passage of new legislation, or changes in the regulatory environment. As of December 31, 2020, there were $3.6 billion of deferred costs included in regulatory assets, $0.4 billion of which were pending final regulatory approval, and $8.4 billion of regulatory liabilities awaiting potential refund or future rate reduction, $0.5 billion of which were pending final regulatory determination.

The principal considerations for our determination that performing procedures relating to the accounting for the effects of cost-based regulation is a critical audit matter are the significant judgment by management in the ongoing evaluation of the recovery of regulatory assets and refund of regulatory liabilities, and applying guidance contained in rate orders and other relevant evidence; which in turn led to significant audit effort and a high degree of auditor subjectivity in performing procedures and in evaluating audit evidence relating to management's judgments about the probability of recovery of regulatory assets and refund of regulatory liabilities.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's assessment of regulatory proceedings, including the probability of recovery of regulatory assets and refund of regulatory liabilities. These procedures also included, among others, evaluating the reasonableness of management's assessment of probability of future recovery for regulatory assets and refund of regulatory liabilities. Testing of regulatory assets and liabilities, including those subject to pending rate cases, also involved evaluating the provisions and formulas outlined in rate orders, other regulatory correspondence, and application of regulatory precedents.

Valuation of Level 3 Risk Management Commodity Contracts

As described in Notes 1, 10 and 11 to the consolidated financial statements, the Company employs risk management commodity contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, over-the-counter swaps and options to accomplish its risk management strategies. Certain over-the-counter and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. The fair value of these risk management commodity contracts is estimated based on available market information including valuation models that estimate future energy prices based on existing market and broker quotes, and other assumptions. Fair value estimates involve significant uncertainties and matters of significant judgement including future commodity prices and future price volatility. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. Management utilized such unobservable pricing data to value its Level 3 risk management commodity contract assets and liabilities, which totaled $256.3 million and $174.8 million, as of December 31, 2020, respectively.

The principal considerations for our determination that performing procedures relating to the valuation of Level 3 risk management commodity contracts is a critical audit matter are the significant judgment and estimation by management when developing the fair value of the commodity contracts; which in turn led to significant audit effort and a high degree of auditor subjectivity in performing procedures and in evaluating audit evidence relating to the unobservable assumptions for projections of future commodity prices and future price volatilities used within management's discounted cash flow models. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's valuation of the risk management commodity contracts, including controls over the assumptions used to value the Level 3 risk management commodity contracts. These procedures also included, among others, testing the data used in and management's process for developing the fair value of the Level 3 risk management commodity contracts. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the discounted cash flow models and reasonableness of the future commodity prices and future price volatilities assumptions.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 25, 2021

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP's internal control over financial reporting was effective as of December 31, 2020.

PricewaterhouseCoopers LLP, AEP's independent registered public accounting firm has issued an audit report on the effectiveness of AEP's internal control over financial reporting as of December 31, 2020. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2020, 2019 and 2018
(in millions, except per-share and share amounts)

	Years Ended December 31, 2020	2019	2018
REVENUES			
Vertically Integrated Utilities	$ 8,753.2	$ 9,245.7	$ 9,556.7
Transmission and Distribution Utilities	4,238.7	4,319.0	4,552.3
Generation & Marketing	1,621.0	1,721.8	1,818.1
Other Revenues	305.6	274.9	268.6
TOTAL REVENUES	14,918.5	15,561.4	16,195.7
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	1,439.3	1,940.9	2,359.4
Purchased Electricity for Resale	2,930.4	3,165.2	3,427.1
Other Operation	2,572.4	2,743.7	2,979.2
Maintenance	1,010.4	1,213.9	1,247.4
Asset Impairments and Other Related Charges	—	156.4	70.6
Depreciation and Amortization	2,682.8	2,514.5	2,286.6
Taxes Other Than Income Taxes	1,295.5	1,234.5	1,142.7
TOTAL EXPENSES	11,930.8	12,969.1	13,513.0
OPERATING INCOME	2,987.7	2,592.3	2,682.7
Other Income (Expense):			
Other Income	57.0	26.6	18.2
Allowance for Equity Funds Used During Construction	148.1	168.4	132.5
Non-Service Cost Components of Net Periodic Benefit Cost	119.0	120.0	124.5
Interest Expense	(1,165.7)	(1,072.5)	(984.4)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	2,146.1	1,834.8	1,973.5
Income Tax Expense (Benefit)	40.5	(12.9)	115.3
Equity Earnings of Unconsolidated Subsidiaries	91.1	72.1	73.1
NET INCOME	2,196.7	1,919.8	1,931.3
Net Income (Loss) Attributable to Noncontrolling Interests	(3.4)	(1.3)	7.5
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2,200.1	$ 1,921.1	$ 1,923.8
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	495,718,223	493,694,345	492,774,600
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.44	$ 3.89	$ 3.90
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	497,226,867	495,306,238	493,758,277
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.42	$ 3.88	$ 3.90

See Notes to Financial Statements of Registrants beginning on page 75.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2020, 2019 and 2018
(in millions)

	Years Ended December 31,		
	2020	**2019**	**2018**
Net Income	$ 2,196.7	$ 1,919.8	$ 1,931.3
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $1.8, $(21.1) and $3.9 in 2020, 2019 and 2018, Respectively	6.9	(79.4)	14.6
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(1.9), $(1.5) and $(1.4) in 2020, 2019 and 2018, Respectively	(7.0)	(5.6)	(5.3)
Pension and OPEB Funded Status, Net of Tax of $16.7, $15.3 and $(8.8) in 2020, 2019 and 2018, Respectively	62.7	57.7	(33.0)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	62.6	(27.3)	(23.7)
TOTAL COMPREHENSIVE INCOME	2,259.3	1,892.5	1,907.6
Total Comprehensive Income (Loss) Attributable To Noncontrolling Interests	(3.4)	(1.3)	7.5
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2,262.7	$ 1,893.8	$ 1,900.1

See Notes to Financial Statements of Registrants beginning on page 75.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2020, 2019 and 2018
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2017	512.2	$ 3,329.4	$ 6,398.7	$ 8,626.7	$ (67.8)	$ 26.6	$ 18,313.6
Issuance of Common Stock	1.3	8.0	65.6				73.6
Common Stock Dividends				(1,251.1) (a)		(4.4)	(1,255.5)
Other Changes in Equity			21.8			1.3	23.1
ASU 2018-02 Adoption				14.0	(17.0)		(3.0)
ASU 2016-01 Adoption				11.9	(11.9)		—
Net Income				1,923.8		7.5	1,931.3
Other Comprehensive Loss					(23.7)		(23.7)
TOTAL EQUITY – DECEMBER 31, 2018	513.5	3,337.4	6,486.1	9,325.3	(120.4)	31.0	19,059.4
Issuance of Common Stock	0.9	6.0	59.3				65.3
Common Stock Dividends				(1,345.5) (a)		(4.5)	(1,350.0)
Other Changes in Equity			(9.8) (b)			2.2	(7.6)
Acquisition of Sempra Renewables LLC						134.8	134.8
Acquisition of Santa Rita East						118.8	118.8
Net Income (Loss)				1,921.1		(1.3)	1,919.8
Other Comprehensive Loss					(27.3)		(27.3)
TOTAL EQUITY – DECEMBER 31, 2019	514.4	3,343.4	6,535.6	9,900.9	(147.7)	281.0	19,913.2
Issuance of Common Stock	2.4	15.9	139.1				155.0
Common Stock Dividends				(1,415.0) (a)		(9.9)	(1,424.9)
Other Changes in Equity			(85.8) (c)			(0.4)	(86.2)
ASU 2016-13 Adoption				1.8			1.8
Acquisition of Incremental Interest in Santa Rita East						(43.7)	(43.7)
Net Income (Loss)				2,200.1		(3.4)	2,196.7
Other Comprehensive Income					62.6		62.6
TOTAL EQUITY – DECEMBER 31, 2020	516.8	$ 3,359.3	$ 6,588.9	$ 10,687.8	$ (85.1)	$ 223.6	$ 20,774.5

(a) Cash dividends declared per AEP common share were $2.84, $2.71 and $2.53 for the years ended December 31, 2020, 2019 and 2018, respectively.
(b) Includes $(62) million related to a forward equity purchase contract associated with the issuance of Equity Units. See "Equity Units" section of Note 14 for additional information.
(c) Includes $(121) million related to a forward equity purchase contract associated with the issuance of Equity Units. See "Equity Units" section of Note 14 for additional information.

See Notes to Financial Statements of Registrants beginning on page 75.

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

	December 31, 2020	December 31, 2019
CURRENT ASSETS		
Cash and Cash Equivalents	$ 392.7	$ 246.8
Restricted Cash (December 31, 2020 and 2019 Amounts Include $45.6 and $185.8, Respectively, Related to Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Santa Rita East)	45.6	185.8
Other Temporary Investments (December 31, 2020 and 2019 Amounts Include $194.6 and $187.8, Respectively, Related to EIS and Transource Energy)	200.8	202.7
Accounts Receivable:		
Customers	613.6	625.3
Accrued Unbilled Revenues	248.7	222.4
Pledged Accounts Receivable – AEP Credit	1,018.4	873.9
Miscellaneous	33.1	27.2
Allowance for Uncollectible Accounts	(71.1)	(43.7)
Total Accounts Receivable	1,842.7	1,705.1
Fuel	629.4	528.5
Materials and Supplies	680.6	640.7
Risk Management Assets	94.7	172.8
Accrued Tax Benefits	185.3	85.8
Regulatory Asset for Under-Recovered Fuel Costs	90.7	92.9
Margin Deposits	62.0	60.4
Prepayments and Other Current Assets	127.0	156.3
TOTAL CURRENT ASSETS	4,351.5	4,077.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	23,133.9	22,762.4
Transmission	27,886.7	24,808.6
Distribution	23,972.1	22,443.4
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	5,294.6	4,811.5
Construction Work in Progress	4,025.7	4,319.8
Total Property, Plant and Equipment	84,313.0	79,145.7
Accumulated Depreciation and Amortization	20,411.4	19,007.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	63,901.6	60,138.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,527.0	3,158.8
Securitized Assets	657.0	858.1
Spent Nuclear Fuel and Decommissioning Trusts	3,306.7	2,975.7
Goodwill	52.5	52.5
Long-term Risk Management Assets	242.2	266.6
Operating Lease Assets	866.4	957.4
Deferred Charges and Other Noncurrent Assets	3,852.3	3,407.3
TOTAL OTHER NONCURRENT ASSETS	12,504.1	11,676.4
TOTAL ASSETS	$ 80,757.2	$ 75,892.3

See Notes to Financial Statements of Registrants beginning on page 75.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2020 and 2019
(dollars in millions)

	December 31, 2020	December 31, 2019
CURRENT LIABILITIES		
Accounts Payable	$ 1,709.7	$ 2,085.8
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	592.0	710.0
Other Short-term Debt	1,887.3	2,128.3
Total Short-term Debt	2,479.3	2,838.3
Long-term Debt Due Within One Year (December 31, 2020 and 2019 Amounts Include $198.3 and $565.1, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)	2,086.1	1,598.7
Risk Management Liabilities	78.8	114.3
Customer Deposits	335.6	366.1
Accrued Taxes	1,476.4	1,357.8
Accrued Interest	267.6	243.6
Obligations Under Operating Leases	241.3	234.1
Regulatory Liability for Over-Recovered Fuel Costs	52.6	86.6
Other Current Liabilities	1,199.3	1,373.8
TOTAL CURRENT LIABILITIES	9,926.7	10,299.1
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2020 and 2019 Amounts Include $950.1 and $907, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)	28,986.4	25,126.8
Long-term Risk Management Liabilities	232.8	261.8
Deferred Income Taxes	8,240.9	7,588.2
Regulatory Liabilities and Deferred Investment Tax Credits	8,378.7	8,457.6
Asset Retirement Obligations	2,469.2	2,216.6
Employee Benefits and Pension Obligations	336.4	466.0
Obligations Under Operating Leases	638.4	734.6
Deferred Credits and Other Noncurrent Liabilities	728.0	719.8
TOTAL NONCURRENT LIABILITIES	50,010.8	45,571.4
TOTAL LIABILITIES	59,937.5	55,870.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	—	65.7
Contingently Redeemable Performance Share Awards	45.2	42.9
TOTAL MEZZANINE EQUITY	45.2	108.6
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2020	2019
Shares Authorized	600,000,000	600,000,000
Shares Issued	516,808,354	514,373,631

	December 31, 2020	December 31, 2019
(20,204,160 Shares were Held in Treasury as of December 31, 2020 and 2019, Respectively)	3,359.3	3,343.4
Paid-in Capital	6,588.9	6,535.6
Retained Earnings	10,687.8	9,900.9
Accumulated Other Comprehensive Income (Loss)	(85.1)	(147.7)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	20,550.9	19,632.2
Noncontrolling Interests	223.6	281.0
TOTAL EQUITY	20,774.5	19,913.2
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 80,757.2	$ 75,892.3

See Notes to Financial Statements of Registrants beginning on page 75.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2020, 2019 and 2018
(in millions)

	Years Ended December 31,		
	2020	2019	2018
OPERATING ACTIVITIES			
Net Income	$ 2,196.7	$ 1,919.8	$ 1,931.3
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	2,682.8	2,514.5	2,286.6
Rockport Plant, Unit 2 Operating Lease Amortization	136.5	136.5	—
Deferred Income Taxes	196.1	(17.8)	104.3
Asset Impairments and Other Related Charges	—	156.4	70.6
Allowance for Equity Funds Used During Construction	(148.1)	(168.4)	(132.5)
Mark-to-Market of Risk Management Contracts	66.5	(29.2)	(66.4)
Amortization of Nuclear Fuel	87.5	89.1	113.8
Pension and Postemployment Benefit Reserves	(8.5)	(24.6)	(42.8)
Pension Contributions to Qualified Plan Trust	(110.3)	—	—
Property Taxes	(43.3)	(73.8)	(59.1)
Deferred Fuel Over/Under-Recovery, Net	(31.8)	85.2	189.7
Change in Regulatory Assets	(337.9)	49.5	354.1
Change in Other Noncurrent Assets	(142.5)	(112.8)	(172.1)
Change in Other Noncurrent Liabilities	(54.5)	(116.1)	129.0
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(129.3)	247.8	145.9
Fuel, Materials and Supplies	(142.9)	(248.2)	20.7
Accounts Payable	(35.3)	5.8	36.6
Accrued Taxes, Net	20.1	138.9	153.2
Rockport Plant, Unit 2 Operating Lease Payments	(147.7)	(147.7)	—
Other Current Assets	34.3	70.7	10.5
Other Current Liabilities	(255.5)	(205.5)	149.8
Net Cash Flows from Operating Activities	3,832.9	4,270.1	5,223.2
INVESTING ACTIVITIES			
Construction Expenditures	(6,246.3)	(6,051.4)	(6,310.9)
Purchases of Investment Securities	(1,678.8)	(1,576.0)	(2,067.8)
Sales of Investment Securities	1,644.3	1,494.2	2,010.0
Acquisitions of Nuclear Fuel	(69.7)	(92.3)	(46.1)
Acquisition of Sempra Renewables LLC and Santa Rita East, Net of Cash and Restricted Cash Acquired	—	(918.4)	—
Other Investing Activities	116.6	(0.6)	61.2
Net Cash Flows Used for Investing Activities	(6,233.9)	(7,144.5)	(6,353.6)
FINANCING ACTIVITIES			
Issuance of Common Stock	155.0	65.3	73.6
Issuance of Long-term Debt	5,626.1	4,536.6	4,945.7
Issuance of Short-term Debt with Original Maturities Greater Than 90 Days	1,396.5	—	205.6
Change in Short-term Debt with Original Maturities Less Than 90 Day, Net	(448.4)	928.3	271.4
Retirement of Long-term Debt	(1,339.8)	(1,220.8)	(2,782.0)
Redemption of Short-term Debt with Original Maturities Greater Than 90 Days	(1,307.1)	—	(205.6)
Principal Payments for Finance Lease Obligations	(61.7)	(70.7)	(65.1)
Dividends Paid on Common Stock	(1,424.9)	(1,350.0)	(1,255.5)
Redemption of Noncontrolling Interests	(100.2)	—	—
Other Financing Activities	(88.8)	(25.8)	(26.2)
Net Cash Flows from Financing Activities	2,406.7	2,862.9	1,161.9
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	5.7	(11.5)	31.5
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	432.6	444.1	412.6
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 438.3	$ 432.6	$ 444.1

See Notes to Financial Statements of Registrants beginning on page 75.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

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

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

ORGANIZATION

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

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

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP's public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in the eleven state operating territories in which they operate. The FERC also regulates the Registrants' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

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

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrants' retail public utility subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/ power supply operations and rates except in Ohio and the ERCOT region of Texas. For generation in Ohio, customers who have not switched to a CRES provider for generation pay market-based auction rates. In addition, all OPCo distribution customers paid for certain legacy generation deferral balances that were fully recovered as of December 31, 2019 and continue to pay for certain legacy deferred generation-related costs through PUCO approved riders. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing is conducted by REPs. AEP has one active REP in ERCOT. AEP's nonregulated subsidiaries enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind assets, the power from which is marketed and sold in ERCOT. Power from the Oklaunion Power Station was also marketed and sold by these nonregulated subsidiaries in ERCOT prior to its retirement in September 2020.

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

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

In addition, the FERC regulates the SIA, Operating Agreement, TA and TCA, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA. See Note 16 - Related Party Transactions for additional information.

Principles of Consolidation

AEP's consolidated financial statements include its wholly-owned and majority-owned subsidiaries and VIEs of which AEP is the primary beneficiary. The consolidated financial statements for AEP Texas include the Registrant Subsidiary, its wholly-owned subsidiaries, Transition Funding (consolidated VIEs) and Restoration Funding (a consolidated VIE). The consolidated financial statements for APCo include the Registrant Subsidiary, its wholly-owned subsidiaries and Appalachian Consumer Rate Relief Funding (a consolidated VIE). The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (consolidated VIEs). The consolidated statements of cash flows for OPCo include the Registrant Subsidiary and Ohio Phase-in Recovery Funding (a consolidated VIE) for the years ended December 31, 2019 and 2018. In July 2019, the Ohio Phase-in Recovery funding securitization bonds matured. The consolidated financial statements for SWEPCo include the Registrant Subsidiary, its wholly-owned subsidiary and Sabine (a consolidated VIE). Intercompany items are eliminated in consolidation.

The equity method of accounting is used for equity investments where the Registrants exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income.

AEP, I&M and SWEPCo have ownership interests in generating units that are jointly-owned. The proportionate share of the operating costs associated with such facilities is included on the income statements and the assets and liabilities are reflected on the balance sheets. See Note 17 - Variable Interest Entities and Equity Method Investments and Note 18 - Property, Plant and Equipment for additional information. In October 2020, AEP Texas, PSO and a nonaffiliated joint-owner executed an Environmental Liability and Property Transfer and Asset Purchase Agreement with a nonaffiliated third-party related to the Oklaunion Power Station site. See Note 7 – Acquisitions, Dispositions and Impairments for additional information.

Accounting for the Effects of Cost-Based Regulation

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

Use of Estimates

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

Cash and Cash Equivalents

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

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

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

Reconciliation of Cash, Cash Equivalents and Restricted Cash

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

	December 31, 2020		
	AEP	**AEP Texas**	**APCo**
		(in millions)	
Cash and Cash Equivalents	$ 392.7	$ 0.1	$ 5.8
Restricted Cash	45.6	28.7	16.9
Total Cash, Cash Equivalents and Restricted Cash	$ 438.3	$ 28.8	$ 22.7

	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

Other Temporary Investments (Applies to AEP)

Other Temporary Investments primarily include marketable securities and investments by its protected cell of EIS. These securities have readily determinable fair values and are carried at fair value with changes in fair value recognized in net income. The cost of securities sold is based on the specific identification or weighted-average cost method. See "Fair Value Measurements of Other Temporary Investments" section of Note 11 for additional information.

Inventory

Fossil fuel inventories are carried at average cost with the exception of AGR, which is carried at the lower of average cost or net realizable value. Materials and supplies inventories are carried at average cost.

Accounts Receivable

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

Revenue is recognized over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, the Registrants accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

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

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. 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.

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

APCo, I&M, OPCo, PSO and SWEPCo do not have any significant customers that comprise 10% or more of their operating revenues. AEP Texas had significant transactions with REPs which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable – Customers as of December 31:

Significant Customers of AEP Texas: Reliant Energy, Direct Energy and TXU Energy (a)	**2020**	**2019**	**2018**
Percentage of Total Revenues	46 %	48 %	45 %
Percentage of Accounts Receivable – Customers	40 %	43 %	35 %

(a) In January 2021, NRG Energy, parent company of Reliant Energy, completed a deal to purchase Direct Energy from Centrica.

AEPTCo had significant transactions with AEP Subsidiaries which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Total Accounts Receivable as of December 31:

Significant Customers of AEPTCo: AEP Subsidiaries	2020	2019	2018
Percentage of Total Revenues	78 %	79 %	77 %
Percentage of Total Accounts Receivable	78 %	78 %	84 %

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

Renewable Energy Credits (Applies to all Registrants except AEP Texas and AEPTCo)

In regulated jurisdictions, the Registrants record renewable energy credits (RECs) at cost. For AEP's competitive generation business, management records RECs at the lower of cost or market. The Registrants follow the inventory model for these RECs. RECs expected to be consumed within one year are reported in Materials and Supplies on the balance sheets. RECs with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs are consumed to meet applicable state renewable portfolio standards and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment

Regulated

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

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

Nuclear fuel, including nuclear fuel in the fabrication phase, is included in Other Property, Plant and Equipment on the balance sheets.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in-service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

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

Allowance for Funds Used During Construction and Interest Capitalization

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

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities (Applies to all Registrants except AEPTCo)

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

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

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

Assets in the benefits and nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs (Applies to all Registrants except AEP Texas and AEPTCo)

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily using the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a commission-approved plan to delay refunds or recoveries beyond a one year period. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrants' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. The Registrants share the majority of their Off-system Sales margins to customers either through an active FAC or other rate mechanisms. Where the FAC or Off-system Sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

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

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

Retail and Wholesale Supply and Delivery of Electricity

The Registrants recognize revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrants recognize such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts. In accordance with the applicable state commission's regulatory treatment, PSO and SWEPCo do not include the fuel portion in unbilled revenue, but rather recognize such revenues when billed to customers.

Wholesale transmission revenue is based on FERC-approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations", and are recognized by the Registrants in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets. See Note 19 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

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

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

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

Energy Marketing and Risk Management Activities (Applies to all Registrants except AEPTCo)

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

The Registrants recognize revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

The Registrants use MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The Registrants include realized gains and losses on marketing and risk management transactions in revenues or expense based on the transaction's facts and circumstances. In certain jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

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

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

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over approximately 18 months, beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

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

Income Taxes and Investment and Production Tax Credits

The Registrants use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

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

AEP and subsidiaries apply the deferral methodology for the recognition of ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed in-service, except where regulatory commissions reflect ITCs in the rate-making process, then amortization begins when the cash tax benefit is recognized. Alternatively, PTCs reduce income tax expense as they are earned. PTCs are earned when electricity is produced.

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

Excise Taxes (Applies to all Registrants except AEPTCo)

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

Debt

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

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

Goodwill (Applies to AEP)

When AEP acquires a business, as defined by the accounting guidance for "Business Combinations," management recognizes all acquired assets and liabilities at their fair value. To the extent that consideration exceeds the net fair value of the identified assets and liabilities, goodwill is recognized on the balance sheets. Goodwill is not amortized. Management tests acquired goodwill at the reporting unit level for impairment at least annually at its estimated fair value. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods.

Pension and OPEB Plans (Applies to all Registrants except AEPTCo)

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

Investments Held in Trust for Future Liabilities (Applies to all Registrants except AEPTCo)

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

Benefit Plans

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

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

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

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

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

OPEB Plans Assets	Target
Equity	49 %
Fixed Income	49 %
Cash and Cash Equivalents	2 %

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

For equity investments, the concentration limits are generally as follows:

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

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

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

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

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2020 and 2019, the fair value of securities on loan as part of the program was $177 million and $246 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2020 and 2019.

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

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

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

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

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

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

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies debt securities in the trust funds as available-for-sale due to their long-term purpose.

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

Comprehensive Income (Loss) (Applies to all Registrants except AEPTCo)

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

Stock-Based Compensation Plans

As of December 31, 2020, AEP had performance shares and restricted stock units outstanding under the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP). Upon vesting, all outstanding performance shares and restricted stock units settle in AEP common stock. Performance units awarded prior to 2017 and restricted stock units granted after January 1, 2013 and prior to January 1, 2017 that vested to executive officers were settled in cash. During 2019, all of the remaining performance units and restricted stock units that settle in cash were settled. The impact of AEP's stock-based compensation plans are insignificant to the financial statements of the Registrant Subsidiaries.

AEP maintains a variety of tax qualified and non-qualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes AEP career shares maintained under the American Electric Power System Stock Ownership Requirement Plan (SORP), which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. AEP career shares are derived from vested performance shares granted to employees under the 2015 LTIP. AEP career shares accrue additional dividend shares in an amount equal to dividends paid on AEP common shares at the closing market price on the dividend payments date. All AEP career shares are settled in shares of AEP common stock after the executive's service with AEP ends.

Performance shares awarded after January 1, 2017 are classified as temporary equity in the Mezzanine Equity section of the balance sheets until the awards vest. Upon vesting, the performance shares are classified as permanent equity. These awards may be settled in cash upon an employee's qualifying termination due to a change in control. Because such event is not solely within the control of the company, these awards are classified outside of permanent equity until the awards vest.

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

Management measures and recognizes compensation expense for all share-based payment awards to employees and directors based on estimated fair values. For share-based payment awards with service only vesting conditions, management recognizes compensation expense on a straight-line basis. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2020, 2019 and 2018 is based on the number of outstanding awards at the end of each period without a reduction for estimated forfeitures. AEP accounts for forfeitures in the period in which they occur.

For the years ended December 31, 2020, 2019 and 2018, compensation cost is included in Net Income for the performance shares, career shares, restricted stock units and the non-employee director's stock units. Compensation cost may also be capitalized. See Note 15 - Stock-based Compensation for additional information.

Equity Investment in Unconsolidated Entities (Applies to AEP and SWEPCo)

The equity method of accounting is used for equity investments where either AEP or SWEPCo exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings (Loss) of Unconsolidated Subsidiaries on the statements of income. AEP and SWEPCo regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

AEP has various significant equity method investments, which include ETT, DHLC and five wind farms acquired in the purchase of Sempra Renewables LLC. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

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 reduced demand for energy, particularly from commercial and industrial customers in 2020. The Registrants have taken steps to mitigate the potential risks to customers, suppliers and employees posed by the spread of COVID-19.

As of December 31, 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 year ended December 31, 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 initially recorded within the AEPSC and then allocated among affiliated entities including the Registrant Subsidiaries. The impact of this program was immaterial on the Registrants' financial statements as of December 31, 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 options and awards.

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

	Years Ended December 31,					
	2020		2019		2018	
	(in millions, except per-share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$2,200.1		$1,921.1		$1,923.8	
Weighted-Average Number of Basic AEP Common Shares Outstanding	495.7	$ 4.44	493.7	$ 3.89	492.8	$ 3.90
Weighted-Average Dilutive Effect of Stock-Based Awards	1.5	(0.02)	1.6	(0.01)	1.0	—
Weighted-Average Number of Diluted AEP Common Shares Outstanding	497.2	$ 4.42	495.3	$ 3.88	493.8	$ 3.90

Equity Units are potentially dilutive securities but were excluded from the calculation of diluted EPS for the years ended December 31, 2020 and 2019, as the dilutive stock price thresholds were not met. See Note 14 - Financing Activities for additional information related to Equity Units.

There were 128 thousand antidilutive shares outstanding as of December 31, 2020. There were no antidilutive shares outstanding as of December 31, 2019 and 2018.

Reclassifications

Certain reclassifications have been made in the 2019 financial statements and notes to conform to the 2020 presentation.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2020, 2019 and 2018:

2020

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 2,487.5	$ 364.2	$ 249.0	$ 507.8	$ 393.3	$ 275.0	$ 171.9	$ 271.2
Amortization of Certain Securitized Assets	171.3	171.3	—	—	—	—	—	—
Amortization of Regulatory Assets and Liabilities	24.0	(5.7)	—	(0.3)	18.3	1.6	1.6	1.5
Total Depreciation and Amortization	$ 2,682.8	$ 529.8	$ 249.0	$ 507.5	$ 411.6	$ 276.6	$ 173.5	$ 272.7

2019

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 2,203.7	$ 365.9	$ 176.0	$ 466.5	$ 330.6	$ 229.4	$ 162.5	$ 247.9
Amortization of Certain Securitized Assets	280.7	258.7	—	—	—	22.0	—	—
Amortization of Regulatory Assets and Liabilities	30.1	(2.3)	—	0.3	20.0	(10.5)	7.0	1.2
Total Depreciation and Amortization	$ 2,514.5	$ 622.3	$ 176.0	$ 466.8	$ 350.6	$ 240.9	$ 169.5	$ 249.1

2018

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,965.0	$ 262.2	$ 133.9	$ 428.1	$ 278.9	$ 232.6	$ 155.5	$ 237.0
Amortization of Certain Securitized Assets	287.9	240.0	—	—	—	47.9	—	—
Amortization of Regulatory Assets and Liabilities	33.7	(2.6)	—	0.3	14.2	(20.8)	8.5	2.5
Total Depreciation and Amortization	$ 2,286.6	$ 499.6	$ 133.9	$ 428.4	$ 293.1	$ 259.7	$ 164.0	$ 239.5

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Years Ended December 31, 2020	2019	2018
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 1,029.1	$ 1,022.5	$ 939.3
Income Taxes	(49.1)	6.1	(24.7)
Noncash Investing and Financing Activities:			
Acquisitions Under Finance Leases	44.2	87.5	55.6
Construction Expenditures Included in Current Liabilities as of December 31,	975.4	1,341.1	1,120.4
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	5.5	—	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	33.4	0.1	4.0
Noncash Contribution of Assets by Noncontrolling Interest	—	—	84.0
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	2.6	0.3	2.2
Noncontrolling Interest Assumed with Sempra Renewables LLC and Santa Rita East Acquisition	—	253.4	—
Liabilities Assumed with Sempra Renewable LLC and Santa Rita East Acquisition	—	32.4	—
Forward Equity Purchase Contracts Included in Current and Noncurrent Liabilities as of December 31,	110.6	47.3	—

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.

Management adopted ASU 2020-04 and its related implementation guidance effective January 1, 2021. There was no impact to results of operations, financial position or cash flows upon initial adoption. Management is applying the accounting guidance as relevant contract and hedge accounting relationship modifications are made during the course of the reference rate reform transition period, which ends on December 31, 2022. The guidance generally allows for contract modifications solely related to the replacement of the reference rate to be accounted for as a continuation of the existing contract instead of as an extinguishment of the contract, and would therefore, not trigger certain accounting impacts that would otherwise be required. It also allows entities to change certain critical terms of existing hedge accounting relationships that are affected by reference rate reform. These changes would not require de-designating the hedge accounting relationship.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants except for AEPTCo. AEPTCo does not have any components of other comprehensive income for any period presented in the financial statements.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2020, 2019 and 2018. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 - Benefit Plans for additional information.

AEP

For the Year Ended December 31, 2020	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate		Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
				(in millions)		
Balance in AOCI as of December 31, 2019	$ (103.5)	$ (11.5)		$ 130.7	$ (163.4)	$ (147.7)
Change in Fair Value Recognized in AOCI	(89.2)	(39.9)	(a)	—	62.7	(66.4)
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	(0.4)	—		—	—	(0.4)
Purchased Electricity for Resale (b)	167.6	—		—	—	167.6
Interest Expense (b)	—	4.9		—	—	4.9
Amortization of Prior Service Cost (Credit)	—	—		(19.2)	—	(19.2)
Amortization of Actuarial (Gains) Losses	—	—		10.3	—	10.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	167.2	4.9		(8.9)	—	163.2
Income Tax (Expense) Benefit	35.1	1.0		(1.9)	—	34.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	132.1	3.9		(7.0)	—	129.0
Net Current Period Other Comprehensive Income (Loss)	42.9	(36.0)		(7.0)	62.7	62.6
Balance in AOCI as of December 31, 2020	$ (60.6)	$ (47.5)		$ 123.7	$ (100.7)	$ (85.1)

AEP

For the Year Ended December 31, 2019	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ 136.3	$ (221.1)	$ (120.4)
Change in Fair Value Recognized in AOCI	(127.2)	(0.2) (a)	—	57.7	(69.7)
Amount of (Gain) Loss Reclassified from AOCI					
Generation & Marketing Revenues (b)	(0.2)	—	—	—	(0.2)
Purchased Electricity for Resale (b)	59.5	—	—	—	59.5
Interest Expense (b)	—	1.5	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	(19.2)	—	(19.2)
Amortization of Actuarial (Gains) Losses	—	—	12.1	—	12.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	59.3	1.5	(7.1)	—	53.7
Income Tax (Expense) Benefit	12.6	0.2	(1.5)	—	11.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	46.7	1.3	(5.6)	—	42.4
Net Current Period Other Comprehensive Income (Loss)	(80.5)	1.1	(5.6)	57.7	(27.3)
Balance in AOCI as of December 31, 2019	$ (103.5)	$ (11.5)	$ 130.7	$ (163.4)	$ (147.7)

For the Year Ended December 31, 2018	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate	Securities Available for Sale	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)
Change in Fair Value Recognized in AOCI	37.3	2.3	—	—	(33.0)	6.6
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (b)	(0.1)	—	—	—	—	(0.1)
Purchased Electricity for Resale (b)	(32.6)	—	—	—	—	(32.6)
Interest Expense (b)	—	1.1	—	—	—	1.1
Amortization of Prior Service Cost (Credit)	—	—	—	(19.5)	—	(19.5)
Amortization of Actuarial (Gains) Losses	—	—	—	12.8	—	12.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(32.7)	1.1	—	(6.7)	—	(38.3)
Income Tax (Expense) Benefit	(6.9)	0.3	—	(1.4)	—	(8.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(25.8)	0.8	—	(5.3)	—	(30.3)
Net Current Period Other Comprehensive Income (Loss)	11.5	3.1	—	(5.3)	(33.0)	(23.7)
ASU 2018-02 Adoption	(6.1)	(2.7)	—	—	(8.2)	(17.0)
ASU 2016-01 Adoption	—	—	(11.9)	—	—	(11.9)
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ —	$ 136.3	$ (221.1)	$ (120.4)

AEP Texas

For the Year Ended December 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2019	$ (3.4)	$ 4.9	$ (14.3)	$ (12.8)
Change in Fair Value Recognized in AOCI	0.1	—	2.6	2.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.3	—	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.2	—	1.5
Income Tax (Expense) Benefit	0.3	—	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.1	0.2	2.6	3.9
Balance in AOCI as of December 31, 2020	$ (2.3)	$ 5.1	$ (11.7)	$ (8.9)

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.3	—	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.2	—	1.5
Income Tax (Expense) Benefit	0.3	—	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	1.1	2.3
ASU 2018-02 Adoption	—	—	—	—
Balance in AOCI as of December 31, 2019	$ (3.4)	$ 4.9	$ (14.3)	$ (12.8)

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)
Change in Fair Value Recognized in AOCI	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.3	—	1.6
Income Tax (Expense) Benefit	0.3	0.1	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	(1.0)	0.2
ASU 2018-02 Adoption	(0.9)	—	(1.8)	(2.7)
Balance in AOCI as of December 31, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)

APCo

For the Year Ended December 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2019	$ 0.9	$ 9.2	$ (5.1)	$ 5.0
Change in Fair Value Recognized in AOCI	(0.7)	—	7.7	7.0
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.3)	—	—	(1.3)
Amortization of Prior Service Cost (Credit)	—	(5.3)	—	(5.3)
Amortization of Actuarial (Gains) Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)	(4.8)	—	(6.1)
Income Tax (Expense) Benefit	(0.3)	(1.0)	—	(1.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)	(3.8)	—	(4.8)
Net Current Period Other Comprehensive Income (Loss)	(1.7)	(3.8)	7.7	2.2
Balance in AOCI as of December 31, 2020	$ (0.8)	$ 5.4	$ 2.6	$ 7.2

For the Year Ended December 31, 2019	Cash Flow Hedges - Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)
Change in Fair Value Recognized in AOCI	—	—	13.4	13.4
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.3)	—	(5.3)
Amortization of Actuarial (Gains) Losses	—	2.1	—	2.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(3.2)	—	(4.3)
Income Tax (Expense) Benefit	(0.2)	(0.7)	—	(0.9)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.9)	(2.5)	—	(3.4)
Net Current Period Other Comprehensive Income (Loss)	(0.9)	(2.5)	13.4	10.0
Balance in AOCI as of December 31, 2019	$ 0.9	$ 9.2	$ (5.1)	$ 5.0

For the Year Ended December 31, 2018	Cash Flow Hedges: Commodity	Cash Flow Hedges: Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2017	$ —	$ 2.2	$ 14.8	$ (15.7)	$ 1.3
Change in Fair Value Recognized in AOCI	(0.7)	—	—	(2.6)	(3.3)
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale (b)	0.9	—	—	—	0.9
Interest Expense (b)	—	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	—	1.3	—	1.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.9	(1.1)	(3.9)	—	(4.1)
Income Tax (Expense) Benefit	0.2	(0.2)	(0.8)	—	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.7	(0.9)	(3.1)	—	(3.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.9)	(3.1)	(2.6)	(6.6)
ASU 2018-02 Adoption	—	0.5	—	(0.2)	0.3
Balance in AOCI as of December 31, 2018	$ —	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)

I&M

For the Year Ended December 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2019	$ (9.9)	$ 4.9	$ (6.6)	$ (11.6)
Change in Fair Value Recognized in AOCI	—	—	3.1	3.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.7	—	0.7
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	(0.1)	—	1.9
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	(0.1)	—	1.5
Net Current Period Other Comprehensive Income (Loss)	1.6	(0.1)	3.1	4.6
Balance in AOCI as of December 31, 2020	$ (8.3)	$ 4.8	$ (3.5)	$ (7.0)

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)
Change in Fair Value Recognized in AOCI	—	—	0.8	0.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	(0.2)	—	1.8
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	(0.2)	—	1.4
Net Current Period Other Comprehensive Income (Loss)	1.6	(0.2)	0.8	2.2
Balance in AOCI as of December 31, 2019	$ (9.9)	$ 4.9	$ (6.6)	$ (11.6)

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)
Change in Fair Value Recognized in AOCI	—	—	(0.6)	(0.6)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	—	—	1.6
Net Current Period Other Comprehensive Income (Loss)	1.6	—	(0.6)	1.0
ASU 2018-02 Adoption	(2.4)	—	(0.3)	(2.7)
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)

OPCo

For the Year Ended December 31, 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 December 31, 2020	$ —

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2018	$ 1.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
Balance in AOCI as of December 31, 2019	$ —

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 1.9
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.7)
Income Tax (Expense) Benefit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.3)
Net Current Period Other Comprehensive Income (Loss)	(1.3)
ASU 2018-02 Adoption	0.4
Balance in AOCI as of December 31, 2018	$ 1.0

PSO

For the Year Ended December 31, 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)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
Balance in AOCI as of December 31, 2020	$ 0.1

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2018	$ 2.1
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
Balance in AOCI as of December 31, 2019	$ 1.1

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 2.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
ASU 2018-02 Adoption	0.5
Balance in AOCI as of December 31, 2018	$ 2.1

SWEPCo

For the Year Ended December 31, 2020	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2019	$ (1.8)	$ (1.3)	$ 1.8	$ (1.3)
Change in Fair Value Recognized in AOCI	—	—	3.2	3.2
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.9	—	—	1.9
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.1	—	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.9	(1.9)	—	—
Income Tax (Expense) Benefit	0.4	(0.4)	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.5	(1.5)	—	—
Net Current Period Other Comprehensive Income (Loss)	1.5	(1.5)	3.2	3.2
Balance in AOCI as of December 31, 2020	$ (0.3)	$ (2.8)	$ 5.0	$ 1.9

For the Year Ended December 31, 2019	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (0.2)	$ (1.9)	$ (5.4)
Change in Fair Value Recognized in AOCI	—	—	3.7	3.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	1.9	—	—	1.9
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.6	—	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.9	(1.4)	—	0.5
Income Tax (Expense) Benefit	0.4	(0.3)	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.5	(1.1)	—	0.4
Net Current Period Other Comprehensive Income (Loss)	1.5	(1.1)	3.7	4.1
Balance in AOCI as of December 31, 2019	$ (1.8)	$ (1.3)	$ 1.8	$ (1.3)

For the Year Ended December 31, 2018	Cash Flow Hedge – Interest Rate	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (6.0)	$ 1.2	$ 0.8	$ (4.0)
Change in Fair Value Recognized in AOCI	2.3	—	(3.1)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (b)	2.1	—	—	2.1
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.2	—	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.1	(1.8)	—	0.3
Income Tax (Expense) Benefit	0.4	(0.4)	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.7	(1.4)	—	0.3
Net Current Period Other Comprehensive Income (Loss)	4.0	(1.4)	(3.1)	(0.5)
ASU 2018-02 Adoption	(1.3)	—	0.4	(0.9)
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (0.2)	$ (1.9)	$ (5.4)

(a) The change in fair value includes $6 million and $4 million related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC for the years ended December 31, 2020 and December 31, 2019. See “Sempra Renewables LLC” section of Note 17 for additional information.

(b) Amounts reclassified to the referenced line item on the statements of income.

4. RATE MATTERS

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

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

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 quarters of 2020, most state regulators began to lift restrictions on disconnects. As of December 31, 2020, AEP had resumed disconnections in its regulated jurisdictions with the exception of Virginia, Kentucky and Arkansas. Disconnections resumed in Kentucky during January 2021. AEP continues to work with regulators and stakeholders in Virginia and Arkansas and management currently anticipates resuming customary disconnection practices in the first half of 2021. 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 COVID-19 orders, granting deferral authority for incremental COVID-19 expenses, with the exception of Kentucky and 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 $56 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 of 57.5% 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 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 December 31, 2020, AEP Texas' cumulative revenues from interim base rate increases that are subject to review is estimated to be $79 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.

APCo and WPCo Rate Matters (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 deemed 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 included $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 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 December 31, 2020 and 2019, APCo had approximately $35 million and $51 million of Virginia jurisdictional AMR meters as well as $73 million and $75 million of Virginia jurisdictional AMI meters recorded on its balance sheets. APCo pursued full recovery of these assets through its Virginia depreciation rates as discussed above.

In November 2020, the Virginia SCC issued an order concluding that APCo earned above its authorized ROE but within its ROE band for the 2017-2019 period, resulting in no refund to customers and no change to APCo base rates on a prospective basis. The Virginia SCC approved a prospective 9.2% ROE for APCo's 2020-2022 triennial review period with the continuation of a 140 basis point band (8.5% bottom, 9.2% midpoint, 9.9% top). This 9.2% authorized ROE will also be applied to certain APCo rate adjustment clauses. APCo's earnings for the 2020-2022 triennial review will continue to be 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. Conversely, as defined by Virginia law, APCo is also eligible to defer for future recovery certain environmental and major storm operation and maintenance expenses up to the bottom of APCo's authorized Virginia 2020-2022 earnings ROE band. The Virginia SCC also disagreed with APCo's treatment of the retired coal-fired generation assets for regulatory purposes, and instead adopted the Virginia SCC Staff's recommendation to treat the remaining unrecovered costs of the retired coal-fired generation assets as a regulatory asset to be amortized over 10 years as of the June 2015 retirement date. The Virginia SCC's adoption of the Staff's recommended regulatory treatment of the coal-fired generation assets resulted in a net $40 million increase to APCo's 2020 pretax income. In addition, the Virginia SCC's order also included: (a) implementation of the Staff-modified APCo 2017 depreciation study effective January 1, 2018 and (b) implementation of the Staff-modified APCo 2019 depreciation study effective January 1, 2020. The adoption of these depreciation studies resulted in an approximate $47 million reduction to APCo's 2020 pretax income comprised of a $44 million reduction to revenues for amounts recognized in advance of the recording of depreciation expense for the periods January 2018 through October 2020 and a $3 million increase in depreciation expense for the periods November and December 2020. A corresponding regulatory liability was recorded for the $44 million reduction to revenues. The Virginia SCC's approval of APCo's 2019 depreciation study included the ongoing depreciation and recovery of APCo's Virginia AMI/AMR meter balances. In November 2020, APCo filed a notice of appeal with the Virginia Supreme Court.

In December 2020, an intervenor filed a petition at the Virginia SCC requesting reconsideration of: (a) the failure of the Virginia SCC to apply a threshold earnings test to the approved regulatory asset for APCo's closed coal-fired generation assets, (b) the Virginia SCC's use of a 2011 benchmark study to measure the replacement value of capacity for purposes of APCo's 2017 – 2019 earnings test and (c) the reasonableness and prudency of APCo's investments in AMI meters.

In December 2020, APCo filed a petition at the Virginia SCC requesting reconsideration of: (a) certain issues related to APCo's going-forward rates and (b) the Virginia SCC's decision to deny APCo tariff changes that align rates with underlying costs. For APCo's going-forward rates, APCo requested that the Virginia SCC clarify its final order and whether APCo's current rates will allow it to earn a fair return. If the Virginia SCC's order did conclude on APCo's ability to earn a fair return through existing base rates, APCo further requested that the Virginia SCC clarify whether it has the authority to also permit an increase in base rates. If the Virginia SCC did not conclude on APCo's ability to earn a fair return, APCo requested the Virginia SCC provide such a conclusion. In January 2021, as requested by the Virginia SCC, APCo filed briefs related to the petition for reconsideration.

If the Virginia SCC issues an unfavorable ruling related to the intervenor petition, 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 a 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 December 31, 2020, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $1.2 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 required ETT to file for a comprehensive base rate review no later than February 1, 2021. In December 2020, ETT and various intervenors filed a stipulation and settlement agreement with the PUCT. The agreement maintained ETT's previously allowed ROE and capital structure and includes: (a) an $8 million decrease to the current annual revenue requirement effective February 1, 2021, (b) ETT must make an interim transmission cost of service filing by April 1, 2021, (c) a $2 million line item decrease to the revenue requirement determined in each interim transmission cost of service filing until the filing of the next comprehensive base rate review and (d) no determination of prudence on any transmission investment added since ETT's last comprehensive base rate review, which would leave the $1.2 billion of cumulative revenues above subject to review in the next comprehensive base rate review. In January 2021, the PUCT approved the stipulation and settlement agreement. As part of the approved agreement, new rates were implemented in February 2021 and ETT is required to file for a comprehensive base rate review no later than February 1, 2023.

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. In January 2021, I&M updated its Indiana retail rates with the IURC based on actual December 31, 2020 I&M Indiana jurisdictional electric plant in service, resulting in a $60 million net annual base rate increase when compared to I&M Indiana base rate levels prior to March 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 negatively impacts I&M's annual pretax earnings by approximately $20 million starting June 2020.

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

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 UPA expenses and related carrying charges over a 5-year period beginning in December 2022, through an existing purchased power rider.

In January 2021, the KPSC issued an order approving an annual increase in base rates of $52 million based upon an ROE of 9.3% effective with billing cycles mid-January 2021. The order shortened the previously authorized refund period for Excess ADIT that is not subject to normalization requirements being refunded through a rider from 18 years to 3 years. In addition, the order approved recovery of certain annual PJM OATT expenses above/below the corresponding level recovered in base rates through a rider until KPCo's next base case; however, recovery of these transmission costs will be re-examined by the KPSC in KPCo's next base case. The KPSC deferred KPCo's request to authorize a specific recovery period and mechanism for the previously authorized deferral of $50 million of Rockport Plant UPA expenses and related carrying charges to a future proceeding. The order requires KPCo to submit its next base case in June 2023 for rates effective in January 2024.

In February 2021, KPCo filed for rehearing with the KPSC challenging various adjustments that were made in the order and requesting certain clarifications. Also in February 2021, the KPSC issued an order on rehearing that modified the approved annual increase in base rates from $52 million to $53 million and clarified several items, including the timing of the future proceeding to address a specific recovery period and mechanism for the previously authorized deferral of $50 million of Rockport Plant Unit Power Agreement expenses and related carrying charges. The KPSC will initiate a future proceeding to address a specific recovery period and mechanism for the deferral after KPCo makes a written filing identifying the capacity replacement for the Rockport Unit Power Agreement, including the name of the capacity resource and related reasonably anticipated costs.

<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.

In November 2020, PUCO staff filed testimony supporting an annual revenue decrease ranging from $102 million to $123 million based upon an ROE of 8.76% to 9.78%. The difference between OPCo's request and the staff testimony are primarily due to reductions in: (a) demand-side management programs of $40 million, (b) ROE ranging from $9 million to $30 million, (c) employee-related expenses of $23 million, (d) rate base of $19 million, (e) property taxes of $17 million, (f) other various expenses of $15 million, (g) depreciation expense of $11 million and (h) vegetation management programs of $10 million which is subject to over/under-recovery through a rider. The staff's proposed disallowance of plant in service could also result in a write-off of up to $27 million. In addition, the staff recommended that capitalized incentives be excluded from base rates prospectively and also recommended annual revenue caps for the DIR of $57 million in 2021, $78 million in 2022, $96 million in 2023 and $46 million for the first five months of 2024. In December 2020, OPCo and intervenors filed objections. A procedural schedule for the case is pending due to ongoing settlement discussions. 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 ESP 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 $17 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 held in December 2020. SWEPCo expects a decision from the Texas Supreme Court in 2021.

As of December 31, 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.

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. As of December 31, 2020, management estimates that SWEPCo has incurred incremental other operation and maintenance expenses of $84 million ($82 million of which has been deferred as a regulatory asset related to the Louisiana jurisdiction) and incremental capital expenditures of $23 million, all of which is 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. In November 2020, the LPSC issued an order allowing Louisiana utilities, including SWEPCo, to establish a regulatory asset to track and defer expenses associated with Hurricane Delta. As of December 31, 2020, management estimates that SWEPCo has incurred incremental other operation and maintenance expenses of $17 million, which has been deferred as a regulatory asset. Also, management estimates that SWEPCo has incurred incremental capital expenditures of $2 million. 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. Intervenor and staff testimony is scheduled to be filed in March and April 2021, respectively. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2020 Louisiana Base Rate Case

In December 2020, SWEPCo filed a request with the LPSC for a $134 million annual increase in Louisiana base rates based upon a proposed 10.35% ROE. The request would extend the formula rate plan for five years and includes modifications to the formula rate plan to allow for forward-looking transmission costs, reflects the impact of net operating losses associated with the acceleration of certain tax benefits and incorporates future federal corporate income tax changes. The proposed net annual increase: (a) requests a $32 million annual depreciation increase to recover Louisiana's share of the Dolet Hills Power Station, Pirkey Power Plant and Welsh Plant, all of which are expected to be retired early, and (b) includes $10 million annually to recover deferred other operation and maintenance expenses related to Hurricanes Laura and Delta. 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. In February 2021, FERC issued an order extending the waiver through September 2021.

OKTCo Radial Asset Transfer (Applies to AEP, AEPTCo and PSO)

In August 2020, AEPSC filed a request with FERC, on behalf of PSO and OKTCo, to transfer OKTCo's interests in its radial assets to PSO. OKTCo had previously constructed radial assets in the PSO service territory and after the radial assets were placed into service, management determined the radial assets were not eligible to be included as part of OKTCo's SPP OATT formula rates. In October 2020, FERC approved the request and in December 2020, OKTCo completed the transfer of its interest in the radial assets to PSO, through Parent, at net book value. At the transfer date, the net book value of the radial assets were $60 million, before associated tax liabilities. PSO will seek recovery of the radial assets in its next base rate case, which must be filed by October 2021. If PSO does not receive approval to recover the radial assets, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

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

Coal-Fired Generation Plants (Applies to AEP, PSO and SWEPCo)

Compliance with extensive environmental regulations requires significant capital investment in environmental monitoring, installation of pollution control equipment, emission fees, disposal costs and permits. Management continuously evaluates cost estimates of complying with these regulations which has resulted in, and in the future may result in, a decision to retire coal-fired generating facilities earlier than their currently estimated useful lives.

Management is seeking or will seek regulatory recovery, as necessary, for any net book value remaining when the plants are retired. To the extent the net book value of these generation assets are not deemed recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Regulated Generating Units that have been Retired

PSO

In September 2020, the Oklaunion Power Station was retired. As of December 31, 2020, PSO has a regulatory asset for accelerated depreciation pending approval recorded on its balance sheet for $34 million. PSO will seek recovery of the Oklaunion Power Station in its next base rate case. In October 2020, the Oklaunion Power Station site was sold to a nonaffiliated third-party. See "Oklaunion Power Station" section of Note 7 for additional information.

SWEPCo

In April 2016, Welsh Plant, Unit 2 was retired. As part of the 2016 Texas Base Rate Case, SWEPCo received approval from the PUCT to recover the Texas jurisdictional share of Welsh Plant, Unit 2. See "2016 Texas Base Rate Case" section of Note 4 for additional information. As part of the 2019 Arkansas Base Rate Case, SWEPCo received approval from the APSC to recover the Arkansas jurisdictional share of Welsh Plant, Unit 2. In December 2020, SWEPCo filed a request with the LPSC to recover the Louisiana jurisdictional share of Welsh Plant, Unit 2. As of December 31, 2020, SWEPCo has a regulatory asset for plant retirement costs pending approval recorded on its balance sheet for $35 million related to the Louisiana jurisdictional share of Welsh Plant, Unit 2. See "2020 Louisiana Base Rate Case" section of Note 4 for additional information.

Regulated Generating Units to be Retired

PSO

In 2014, PSO received final approval from the EPA to close Northeastern Plant, Unit 3, in 2026. The plant was originally scheduled to close in 2040. As a result of the early retirement date, PSO revised the useful life of Northeastern Plant, Unit 3, to the projected retirement date of 2026 and the incremental depreciation is being deferred as a regulatory asset. In 2016, as part of the 2015 Oklahoma Base Rate Case, the OCC issued an order approving the continued depreciation of Northeastern Plant, Unit 3 through 2040. The order did not approve accelerating the recovery of the incremental depreciation based on the revised retirement date of 2026.

SWEPCo

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. As a result of the announcement, SWEPCo began recording a regulatory asset for accelerated depreciation. In March 2020, management announced plans to retire the plant in 2021.

In November 2020, management announced plans to retire Pirkey Power Plant in 2023 and that it will cease using coal at the Welsh Plant in 2028. As a result of the announcement, SWEPCo began recording a regulatory asset for accelerated depreciation.

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of December 31, 2020, of generating facilities planned for early retirement:

Plant	Net Investment	Accelerated Depreciation Regulatory Asset	Cost of Removal Regulatory Liability		Projected Retirement Date	Current Authorized Recovery Period	Annual Depreciation (a)
			(dollars in millions)				
Northeastern Plant, Unit 3	$ 198.4	$ 110.4	$ 19.8	(b)	2026	(c)	$ 14.9
Dolet Hills Power Station	74.4	71.2	24.0		2021	(d)	60.8
Pirkey Power Plant	199.5	12.2	38.7		2023	(e)	13.8
Welsh Plant, Units 1 and 3	549.8	3.6	57.6	(f)	2028	(g)	33.3

(a) Represents the amount of annual depreciation that has been collected from customers over the prior 12-month period.
(b) Includes Northeastern Plant, Unit 4, which was retired in 2016. Removal of Northeastern Plant, Unit 4, will be performed with Northeastern Plant, Unit 3, after retirement.
(c) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(d) Dolet Hills Power Station is current being recovered through 2026 in the Louisiana jurisdiction and through 2046 in the Arkansas and Texas jurisdictions.
(e) Pirkey Power Plant is currently being recovered through 2025 in the Louisiana jurisdiction and through 2045 in the Arkansas and Texas jurisdictions.
(f) Includes Welsh Plant, Unit 2, which was retired in 2016. Removal of Welsh Plant, Unit 2, will be performed with Welsh Plant, Units 1 and 3, after retirement.
(g) Unit 1 is being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Unit 3 is being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

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 provides 100% 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 rates. SWEPCo's share of the net investment in the Dolet Hills Power Station is $151 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 fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $131 million as of December 31, 2020. Also, as of December 31, 2020, SWEPCo had a net over-recovered fuel balance of $35 million, which includes fuel burned at the Dolet Hills Power Station. Additional operational and land-related costs are expected to be incurred by DHLC and Oxbow and billed to SWEPCo prior to the closure of the Dolet Hills Power Station and recovered through fuel clauses.

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.

Pirkey Power Plant and Related Fuel Operations (Applies to AEP and SWEPCo)

In November 2020, management announced plans to retire the Pirkey Power Plant in 2023. The Pirkey Power Plant costs are recoverable by SWEPCo through base rates. SWEPCo's share of the net investment in the Pirkey Power Plant is $212 million, including CWIP, before cost of removal. Sabine is a mining operator providing mining services to the Pirkey Power Plant. Under the provisions of the mining agreement, SWEPCo is required to pay, as part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. SWEPCo expects fuel deliveries, including billings of all fixed and operating costs, from Sabine to cease during the first quarter of 2023. Under the fuel agreements, SWEPCo's fuel inventory and unbilled fuel costs from mining related activities were $193 million as of December 31, 2020. Also, as of December 31, 2020, SWEPCo had a net over-recovered fuel balance of $35 million, which includes fuel burned at the Pirkey Power Plant. Additional operational costs are expected to be incurred by Sabine and billed to SWEPCo, as well as land-related costs incurred by SWEPCo, prior to the closure of the Pirkey Power Plant and recovered through fuel clauses.

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

2020 Texas Fuel Reconciliation (Applies to AEP and SWEPCo)

In June 2020, SWEPCo filed a fuel reconciliation with the PUCT for its retail operations in Texas for the reconciliation period of March 1, 2017 to December 31, 2019. The fuel reconciliation included total fuel costs of $1.7 billion ($616 million of which is related to the Texas jurisdiction). In January 2021, various parties filed testimony recommending fuel cost disallowances totaling $125 million relating to the Texas jurisdiction. Also in January 2021, SWEPCo filed rebuttal testimony disputing the recommended disallowances. In February 2021, SWEPCo and various parties reached a settlement in principle which resulted in an immaterial impact to SWEPCo's 2020 financial statements. If additional costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31,		Remaining
Current Regulatory Assets	2020	2019	Recovery Period
	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 41.4	$ 44.7	1 year
Under-recovered Fuel Costs - does not earn a return	49.3	48.2	1 year
Total Current Regulatory Assets	$ 90.7	$ 92.9	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Dolet Hills Power Station Accelerated Depreciation	$ 71.2	$ —	
Kentucky Deferred Purchased Power Expenses	41.3	30.2	
Plant Retirement Costs - Unrecovered Plant, Louisiana	35.2	35.2	
Oklaunion Power Station Accelerated Depreciation	34.4	27.4	
Other Regulatory Assets Pending Final Regulatory Approval	38.6	0.7	
Total Regulatory Assets Currently Earning a Return	220.7	93.5	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	134.2	7.2	
Plant Retirement Costs - Asset Retirement Obligation Costs	25.9	30.1	
COVID-19	24.9	—	
Vegetation Management Program - AEP Texas	3.8	29.4	
Other Regulatory Assets Pending Final Regulatory Approval	32.7	21.5	
Total Regulatory Assets Currently Not Earning a Return	221.5	88.2	
Total Regulatory Assets Pending Final Regulatory Approval	442.2	181.7	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (a)	713.1	690.5	23 years
Plant Retirement Costs - Asset Retirement Obligation Costs	107.1	87.4	20 years
Meter Replacement Costs	55.5	65.4	7 years
Ohio Distribution Decoupling	46.6	31.4	2 years
Environmental Control Projects	38.6	41.0	20 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	34.4	13.5	8 years
Cook Plant Uprate Project	30.2	32.6	13 years
Storm-Related Costs	11.5	21.3	2 years
Advanced Metering System	—	26.5	
Other Regulatory Assets Approved for Recovery	94.4	79.6	various
Total Regulatory Assets Currently Earning a Return	1,131.4	1,089.2	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,088.6	1,309.8	12 years
Plant Retirement Costs - Asset Retirement Obligation Costs	212.7	28.8	22 years
Unamortized Loss on Reacquired Debt	120.0	129.0	28 years
Unrealized Loss on Forward Commitments	111.3	106.8	12 years
Vegetation Management	67.8	43.6	5 years
Cook Plant Nuclear Refueling Outage Levelization	39.5	63.8	2 years
PJM/SPP Annual Formula Rate True-up	33.0	7.3	2 years
Postemployment Benefits	29.1	34.2	3 years
OVEC Purchased Power	27.4	1.5	2 years
Fuel and Purchased Power Adjustment Rider	24.0	7.1	2 years
Medicare Subsidy	18.6	23.2	4 years
Other Regulatory Assets Approved for Recovery	181.4	132.8	various
Total Regulatory Assets Currently Not Earning a Return	1,953.4	1,887.9	
Total Regulatory Assets Approved for Recovery	3,084.8	2,977.1	
Total Noncurrent Regulatory Assets	$ 3,527.0	$ 3,158.8	

(a) Northeastern Plant, Unit 3 is approved for recovery through 2040, but expected to retire in 2026. PSO records a regulatory asset for accelerated depreciation. See "Regulated Generating Units to be Retired" section above for additional information.

	AEP		
	December 31,		Remaining
	2020	2019	Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 27.6	$ 77.5	1 year
Over-recovered Fuel Costs - does not pay a return	25.0	9.1	1 year
Total Current Regulatory Liabilities	$ 52.6	$ 86.6	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 2.5	$ —	
Total Regulatory Liabilities Currently Paying a Return	2.5	—	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	1.5	0.2	
Total Regulatory Liabilities Currently Not Paying a Return	1.5	0.2	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	291.6	571.8	
Excess ADIT that is Not Subject to Rate Normalization Requirements	193.3	291.0	(b)
Total Income Tax Related Regulatory Liabilities	484.9	862.8	
Total Regulatory Liabilities Pending Final Regulatory Determination	488.9	863.0	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	3,061.9	2,876.7	(c)
Deferred Investment Tax Credits	4.1	6.2	33 years
Ohio Basic Transmission Cost Rider	—	37.2	
Other Regulatory Liabilities Approved for Payment	25.2	14.4	various
Total Regulatory Liabilities Currently Paying a Return	3,091.2	2,934.5	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,476.6	1,236.0	(d)
Deferred Investment Tax Credits	216.7	215.3	34 years
PJM Transmission Enhancement Refund	56.2	67.3	5 years
Transition and Restoration Charges - Texas	48.2	50.5	9 years
2017-2019 Virginia Triennial Revenue Provision	44.2	—	28 years
Spent Nuclear Fuel	43.1	43.6	(d)
Peak Demand Reduction/Energy Efficiency	26.3	23.0	2 years
Deferred Gain on Sale of Rockport Unit 2	17.9	27.2	2 years
Ohio Enhanced Service Reliability Plan	5.7	29.7	2 years
Virginia Transmission Rate Adjustment Clause	—	28.1	
Other Regulatory Liabilities Approved for Payment	71.0	87.7	various
Total Regulatory Liabilities Currently Not Paying a Return	2,005.9	1,808.4	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	3,485.7	3,303.0	(e)
Excess ADIT that is Not Subject to Rate Normalization Requirements	714.9	890.5	10 years
Income Taxes Subject to Flow Through	(1,407.9)	(1,341.8)	54 years
Total Income Tax Related Regulatory Liabilities	2,792.7	2,851.7	
Total Regulatory Liabilities Approved for Payment	7,889.8	7,594.6	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 8,378.7	$ 8,457.6	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) 2020 and 2019 amounts include approximately $173 million and $172 million, respectively, related to AEP Transmission Holdco's investment in ETT and Transource Energy. AEP Transmission Holdco expects to amortize the balance commensurate with the return of Excess ADIT to ETT and Transource Energy's customers.
(c) Relieved as removal costs are incurred.
(d) Relieved when plant is decommissioned.
(e) Refunded using ARAM.

Regulatory Assets:	AEP Texas		
	December 31, 2020	December 31, 2019	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Advanced Metering System	$ 16.3	$ —	
Total Regulatory Assets Currently Earning a Return	16.3	—	
Regulatory Assets Currently Not Earning a Return			
COVID-19	10.5	—	
Vegetation Management Program	3.8	29.4	
Other Regulatory Assets Pending Final Regulatory Approval	2.3	1.4	
Total Regulatory Assets Currently Not Earning a Return	16.6	30.8	
Total Regulatory Assets Pending Final Regulatory Approval	32.9	30.8	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Meter Replacement Costs	29.3	35.2	6 years
Advanced Metering System	—	26.5	
Total Regulatory Assets Currently Earning a Return	29.3	61.7	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	145.0	172.0	12 years
Vegetation Management Program	22.4	—	5 years
Storm-Related Costs	17.1	—	4 years
Peak Demand Reduction/Energy Efficiency	7.7	3.5	2 years
Other Regulatory Assets Approved for Recovery	12.4	12.6	various
Total Regulatory Assets Currently Not Earning a Return	204.6	188.1	
Total Regulatory Assets Approved for Recovery	233.9	249.8	
Total Noncurrent Regulatory Assets	$ 266.8	$ 280.6	

Regulatory Liabilities:	AEP Texas December 31, 2020	2019	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 2.5	$ —	
Total Regulatory Liabilities Currently Paying a Return	2.5	—	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	—	274.9	
Excess ADIT that is Not Subject to Rate Normalization Requirements	(8.2)	87.1	
Total Income Tax Related Regulatory Liabilities	(8.2)	362.0	
Total Regulatory Liabilities Pending Final Regulatory Determination	(5.7)	362.0	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	718.3	689.6	(b)
Other Regulatory Liabilities Approved for Payment	5.3	10.1	various
Total Regulatory Liabilities Currently Paying a Return	723.6	699.7	
Regulatory Liabilities Currently Not Paying a Return			
Transition and Restoration Charges	48.2	50.5	9 years
Deferred Investment Tax Credits	8.5	9.6	20 years
Other Regulatory Liabilities Approved for Payment	1.2	4.8	various
Total Regulatory Liabilities Currently Not Paying a Return	57.9	64.9	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	506.0	236.5	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	41.7	—	1 years
Income Taxes Subject to Flow Through	(52.7)	(46.2)	28 years
Total Income Tax Related Regulatory Liabilities	495.0	190.3	
Total Regulatory Liabilities Approved for Payment	1,276.5	954.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,270.8	$ 1,316.9	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	AEPTCo December 31, 2020	2019	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets approved for recovery:			
Regulatory Assets Currently Not Earning a Return			
PJM/SPP Annual Formula Rate True-up	$ 15.1	$ 4.2	2 years
Total Regulatory Assets Approved for Recovery	15.1	4.2	
Total Noncurrent Regulatory Assets	$ 15.1	$ 4.2	

Regulatory Liabilities:	AEPTCo December 31, 2020	2019	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 198.6	$ 141.0	(b)
Total Regulatory Liabilities Currently Paying a Return	198.6	141.0	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	531.5	535.7	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	(30.6)	(35.4)	8 years
Income Taxes Subject to Flow Through	(117.7)	(100.4)	38 years
Total Income Tax Related Regulatory Liabilities	383.2	399.9	
Total Regulatory Liabilities Approved for Payment	581.8	540.9	
Total Noncurrent Regulatory Liabilities	$ 581.8	$ 540.9	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	APCo December 31, 2020	APCo December 31, 2019	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Virginia - earns a return	$ 3.3	$ 36.8	1 year
Under-recovered Fuel Costs - does not earn a return	2.0	5.7	1 year
Total Current Regulatory Assets	$ 5.3	$ 42.5	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
COVID-19 - Virginia	$ 3.7	$ —	
Plant Retirement Costs - Materials and Supplies	—	0.5	
Total Regulatory Assets Currently Earning a Return	3.7	0.5	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	25.9	30.1	
Environmental Expense Deferral - Virginia	9.3	—	
COVID-19 - West Virginia	1.5	—	
Other Regulatory Assets Pending Final Regulatory Approval	3.4	—	
Total Regulatory Assets Currently Not Earning a Return	40.1	30.1	
Total Regulatory Assets Pending Final Regulatory Approval	43.8	30.6	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (a)	122.4	86.4	23 years
Other Regulatory Assets Approved for Recovery	1.0	0.5	various
Total Regulatory Assets Currently Earning a Return	123.4	86.9	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	202.7	—	15 years
Pension and OPEB Funded Status	114.4	160.8	12 years
Unamortized Loss on Reacquired Debt	82.1	85.5	25 years
Vegetation Management Program - West Virginia	45.4	43.6	2 years
Virginia Transmission Rate Adjustment Clause	18.8	—	2 years
Peak Demand Reduction/Energy Efficiency	16.8	19.5	6 years
Postemployment Benefits	13.5	15.9	3 years
PJM Annual Formula Rate True-up	12.7	—	2 years
Other Regulatory Assets Approved for Recovery	12.7	14.4	various
Total Regulatory Assets Currently Not Earning a Return	519.1	339.7	
Total Regulatory Assets Approved for Recovery	642.5	426.6	
Total Noncurrent Regulatory Assets	$ 686.3	$ 457.2	

(a) December 31, 2020 amount includes Virginia and West Virginia jurisdictions. December 31, 2019 amount includes West Virginia jurisdiction.

Regulatory Liabilities:	APCo December 31, 2020	APCo December 31, 2019	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 678.9	$ 635.3	(b)
Deferred Investment Tax Credits	0.3	0.5	33 years
Total Regulatory Liabilities Currently Paying a Return	679.2	635.8	
Regulatory Liabilities Currently Not Paying a Return			
2017-2019 Virginia Triennial Revenue Provision	44.2	—	28 years
PJM Transmission Enhancement Refund	16.3	19.5	5 years
Virginia Transmission Rate Adjustment Clause	—	28.1	
Other Regulatory Liabilities Approved for Payment	12.3	18.0	various
Total Regulatory Liabilities Currently Not Paying a Return	72.8	65.6	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	690.0	718.9	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	139.1	210.7	8 years
Income Taxes Subject to Flow Through	(356.4)	(362.3)	24 years
Total Income Tax Related Regulatory Liabilities	472.7	567.3	
Total Regulatory Liabilities Approved for Payment	1,224.7	1,268.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,224.7	$ 1,268.7	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	I&M December 31, 2020	I&M December 31, 2019	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 5.4	$ 3.0	1 year
Total Current Regulatory Assets	$ 5.4	$ 3.0	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.5	$ —	
Total Regulatory Assets Currently Earning a Return	0.5	—	
Regulatory Assets Currently Not Earning a Return			
COVID-19	3.8	—	
Cook Plant Study Costs	—	7.6	
Other Regulatory Assets Pending Final Regulatory Approval	—	0.1	
Total Regulatory Assets Currently Not Earning a Return	3.8	7.7	
Total Regulatory Assets Pending Final Regulatory Approval	4.3	7.7	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	191.5	214.9	8 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	34.4	13.5	8 years
Cook Plant Uprate Project	30.2	32.6	13 years
Deferred Cook Plant Life Cycle Management Project Costs	14.1	15.1	14 years
Cook Plant Turbine	11.1	13.4	18 years
Cook Plant Study Costs - Indiana	10.1	—	15 years
Other Regulatory Assets Approved for Recovery	7.0	6.9	various
Total Regulatory Assets Currently Earning a Return	298.4	296.4	
Regulatory Assets Currently Not Earning a Return			
Cook Plant Nuclear Refueling Outage Levelization	39.5	63.8	2 years
Pension and OPEB Funded Status	25.7	67.5	12 years
Unamortized Loss on Reacquired Debt	15.7	17.2	28 years
Postemployment Benefits	4.9	7.2	3 years
Other Regulatory Assets Approved for Recovery	16.3	22.3	various
Total Regulatory Assets Currently Not Earning a Return	102.1	178.0	
Total Regulatory Assets Approved for Recovery	400.5	474.4	
Total Noncurrent Regulatory Assets	$ 404.8	$ 482.1	

Regulatory Liabilities:	I&M December 31, 2020	I&M December 31, 2019	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, Indiana - does not pay a return	$ 20.8	$ 6.1	1 year
Total Current Regulatory Liabilities	$ 20.8	$ 6.1	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 168.2	$ 166.7	(b)
Other Regulatory Liabilities Approved for Payment	17.4	0.3	various
Total Regulatory Liabilities Currently Paying a Return	185.6	167.0	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	1,476.6	1,236.0	(c)
Spent Nuclear Fuel	43.1	43.6	(c)
Deferred Investment Tax Credits	21.3	25.8	19 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	13.3	17.0	2 years
PJM Transmission Enhancement Refund	9.9	11.8	5 years
Deferred Gain on Sale of Rockport Unit 2	7.2	10.9	2 years
Other Regulatory Liabilities Approved for Payment	30.1	24.9	various
Total Regulatory Liabilities Currently Not Paying a Return	1,601.5	1,370.0	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	450.6	470.9	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	136.2	184.5	4 years
Income Taxes Subject to Flow Through	(332.0)	(301.0)	20 years
Total Income Tax Related Regulatory Liabilities	254.8	354.4	
Total Regulatory Liabilities Approved for Payment	2,041.9	1,891.4	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 2,041.9	$ 1,891.4	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Relieved when plant is decommissioned.
(d) Refunded using ARAM.

Regulatory Assets:	OPCo December 31, 2020	2019	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
COVID-19	$ 4.4	$ —	
Storm-Related Costs	4.0	—	
Other Regulatory Assets Pending Final Regulatory Approval	—	0.1	
Total Regulatory Assets Pending Final Regulatory Approval	8.4	0.1	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Ohio Distribution Decoupling	46.6	31.4	2 years
Ohio Basic Transmission Cost Rider	12.3	—	2 years
Other Regulatory Assets Approved for Recovery	1.3	—	various
Total Regulatory Assets Currently Earning a Return	60.2	31.4	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	130.7	167.3	12 years
Unrealized Loss on Forward Commitments	110.0	103.6	12 years
OVEC Purchased Power	27.4	1.5	2 years
Smart Grid Costs	19.2	13.7	2 years
Distribution Investment Rider	7.4	10.9	2 years
Postemployment Benefits	6.7	7.6	3 years
Other Regulatory Assets Approved for Recovery	15.8	15.7	various
Total Regulatory Assets Currently Not Earning a Return	317.2	320.3	
Total Regulatory Assets Approved for Recovery	377.4	351.7	
Total Noncurrent Regulatory Assets	$ 385.8	$ 351.8	

Regulatory Liabilities:	OPCo December 31, 2020	2019	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - does not pay a return	$ 3.9	$ 2.8	1 year
Total Current Regulatory Liabilities	$ 3.9	$ 2.8	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 0.2	$ 0.2	
Total Regulatory Liabilities Pending Final Regulatory Determination	0.2	0.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	458.4	446.3	(b)
Ohio Basic Transmission Cost Rider	—	37.2	
Other Regulatory Liabilities Approved for Payment	—	1.3	
Total Regulatory Liabilities Currently Paying a Return	458.4	484.8	
Regulatory Liabilities Currently Not Paying a Return			
PJM Transmission Enhancement Refund	24.5	29.4	5 years
Peak Demand Reduction/Energy Efficiency	19.9	19.7	2 years
Ohio Enhanced Service Reliability Plan	5.7	29.7	2 years
Other Regulatory Liabilities Approved for Payment	0.7	2.9	various
Total Regulatory Liabilities Currently Not Paying a Return	50.8	81.7	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	334.6	341.6	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	223.9	252.3	8 years
Income Taxes Subject to Flow Through	(62.7)	(69.7)	29 years
Total Income Tax Related Regulatory Liabilities	495.8	524.2	
Total Regulatory Liabilities Approved for Payment	1,005.0	1,090.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,005.2	$ 1,090.9	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	PSO December 31, 2020	PSO December 31, 2019	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ 30.1	$ —	1 year
Total Current Regulatory Assets	$ 30.1	$ —	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Oklaunion Power Station Accelerated Depreciation	$ 34.4	$ 27.4	
Total Regulatory Assets Currently Earning a Return	34.4	27.4	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	15.8	7.2	
COVID-19	0.3	—	
Total Regulatory Assets Currently Not Earning a Return	16.1	7.2	
Total Regulatory Assets Pending Final Regulatory Approval	50.5	34.6	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant (a)	180.8	167.0	20 years
Environmental Control Projects	26.5	27.8	20 years
Meter Replacement Costs	26.2	30.2	7 years
Storm-Related Costs	11.5	21.3	2 years
Red Rock Generating Facility	8.2	8.4	36 years
Other Regulatory Assets Approved for Recovery	0.5	0.6	various
Total Regulatory Assets Currently Earning a Return	253.7	255.3	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	52.3	73.4	12 years
Unamortized Loss on Reacquired Debt	6.1	6.5	18 years
Other Regulatory Assets Approved for Recovery	12.4	5.4	various
Total Regulatory Assets Currently Not Earning a Return	70.8	85.3	
Total Regulatory Assets Approved for Recovery	324.5	340.6	
Total Noncurrent Regulatory Assets	$ 375.0	$ 375.2	

(a) Northeastern Plant, Unit 3 is approved for recovery through 2040, but expected to retire in 2026. PSO records a regulatory asset for accelerated depreciation. See "Regulated Generating Units to be Retired" section above for additional information.

Regulatory Liabilities:	PSO December 31, 2020	PSO December 31, 2019	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	$ —	$ 63.9	
Total Current Regulatory Liabilities	$ —	$ 63.9	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 289.9	$ 286.8	(b)
Total Regulatory Liabilities Currently Paying a Return	289.9	286.8	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	51.0	51.5	24 years
Other Regulatory Liabilities Approved for Payment	1.3	4.7	various
Total Regulatory Liabilities Currently Not Paying a Return	52.3	56.2	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	397.0	405.8	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	71.3	96.3	4 years
Income Taxes Subject to Flow Through	(8.3)	(7.9)	27 years
Total Income Tax Related Regulatory Liabilities	460.0	494.2	
Total Regulatory Liabilities Approved for Payment	802.2	837.2	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 802.2	$ 837.2	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	SWEPCo December 31, 2020	SWEPCo December 31, 2019	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return (a)	$ 2.6	$ 4.9	1 year
Total Current Regulatory Assets	$ 2.6	$ 4.9	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Dolet Hills Power Station Accelerated Depreciation	$ 71.2	$ —	
Plant Retirement Costs - Unrecovered Plant, Louisiana	35.2	35.2	
Pirkey Power Plant Accelerated Depreciation	12.2	—	
Welsh Plant, Units 1 and 3 Accelerated Depreciation	3.6	—	
Other Regulatory Assets Pending Final Regulatory Approval	2.2	0.2	
Total Regulatory Assets Currently Earning a Return	124.4	35.4	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs	99.3	—	
Asset Retirement Obligation - Louisiana	9.1	7.2	
Other Regulatory Assets Pending Final Regulatory Approval	14.5	3.7	
Total Regulatory Assets Currently Not Earning a Return	122.9	10.9	
Total Regulatory Assets Pending Final Regulatory Approval	247.3	46.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant, Arkansas	14.4	15.1	22 years
Environmental Controls Projects	12.1	13.2	12 years
Other Regulatory Assets Approved for Recovery	7.1	8.9	various
Total Regulatory Assets Currently Earning a Return	33.6	37.2	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	89.1	102.6	12 years
Plant Retirement Costs - Unrecovered Plant, Texas	16.1	16.6	21 years
Other Regulatory Assets Approved for Recovery	17.0	19.7	various
Total Regulatory Assets Currently Not Earning a Return	122.2	138.9	
Total Regulatory Assets Approved for Recovery	155.8	176.1	
Total Noncurrent Regulatory Assets	$ 403.1	$ 222.4	

(a) December 31, 2020 amount includes Louisiana jurisdiction. December 31, 2019 amount includes Arkansas jurisdiction.

Regulatory Liabilities:	SWEPCo December 31, 2020	SWEPCo December 31, 2019	Remaining Refund Period
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return (a)	$ 37.6	$ 13.6	1 year
Total Current Regulatory Liabilities	$ 37.6	$ 13.6	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (b)			
Excess ADIT Associated with Certain Depreciable Property	$ 291.6	$ 297.0	
Excess ADIT that is Not Subject to Rate Normalization Requirements	21.8	22.7	
Total Regulatory Liabilities Pending Final Regulatory Determination	313.4	319.7	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	470.9	453.4	(c)
Other Regulatory Liabilities Approved for Payment	2.4	2.8	various
Total Regulatory Liabilities Currently Paying a Return	473.3	456.2	
Regulatory Liabilities Currently Not Paying a Return			
Peak Demand Reduction/Energy Efficiency	5.2	6.0	2 years
Deferred Investment Tax Credits	1.8	3.1	10 years
Other Regulatory Liabilities Approved for Payment	1.2	1.7	various
Total Regulatory Liabilities Currently Not Paying a Return	8.2	10.8	
Income Tax Related Regulatory Liabilities (b)			
Excess ADIT Associated with Certain Depreciable Property	332.5	339.4	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	11.5	27.8	(e)
Income Taxes Subject to Flow Through	(275.5)	(261.6)	28 years
Total Income Tax Related Regulatory Liabilities	68.5	105.6	
Total Regulatory Liabilities Approved for Payment	550.0	572.6	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 863.4	$ 892.3	

(a) December 31, 2020 amount includes Arkansas and Texas jurisdictions. December 31, 2019 amount includes Texas and Louisiana jurisdictions.
(b) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base.
(c) Relieved as removal costs are incurred.
(d) Refunded using ARAM.
(e) Current balance represents revisions to balances for jurisdictions having previously issued orders on treatment for refund, refund period to be addressed in future proceedings.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

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

COMMITMENTS (Applies to all Registrants except AEP Texas and AEPTCo)

The AEP System has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following tables summarize the Registrants' actual contractual commitments as of December 31, 2020:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 763.9	$ 715.1	$ 212.9	$ 381.5	$ 2,073.4
Energy and Capacity Purchase Contracts	211.6	291.8	277.0	928.5	1,708.9
Total	$ 975.5	$ 1,006.9	$ 489.9	$ 1,310.0	$ 3,782.3

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 362.8	$ 217.6	$ 11.6	$ 16.3	$ 608.3
Energy and Capacity Purchase Contracts	35.5	72.5	73.9	230.2	412.1
Total	$ 398.3	$ 290.1	$ 85.5	$ 246.5	$ 1,020.4

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 157.7	$ 278.9	$ 189.3	$ 332.7	$ 958.6
Energy and Capacity Purchase Contracts	165.2	196.7	60.9	254.6	677.4
Total	$ 322.9	$ 475.6	$ 250.2	$ 587.3	$ 1,636.0

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 28.8	$ 58.2	$ 58.1	$ 263.3	$ 408.4

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 25.3	$ 36.2	$ —	$ —	$ 61.5
Energy and Capacity Purchase Contracts	89.6	77.4	66.8	160.0	393.8
Total	$ 114.9	$ 113.6	$ 66.8	$ 160.0	$ 455.3

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 68.5	$ 39.2	$ —	$ —	$ 107.7
Energy and Capacity Purchase Contracts	8.3	8.4	8.4	4.2	29.3
Total	$ 76.8	$ 47.6	$ 8.4	$ 4.2	$ 137.0

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

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 December 31, 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 December 31, 2020 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 179.8	January 2021 to December 2021
AEP Texas	2.2	July 2021

Guarantees of Equity Method Investees (Applies to AEP)

In April 2019, AEP acquired Sempra Renewables LLC. The transaction resulted in the acquisition of a 50% ownership interest in five non-consolidated joint ventures and the acquisition of two tax equity partnerships. Parent has issued guarantees over the performance of the joint ventures. If a joint venture were to default on payments or performance, Parent would be required to make payments on behalf of the joint venture. As of December 31, 2020, the maximum potential amount of future payments associated with these guarantees was $157 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. See "Acquisitions" section of Note 7 for additional information.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 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 activity conducted on their behalf. AEPSC also conducts power purchase-and-sale activity on behalf of PSO and SWEPCo, who are jointly and severally liable for activity conducted on their behalf.

Lease Obligations

Certain Registrants lease equipment under master lease agreements. See “Master Lease Agreements” and “AEPRO Boat and Barge Leases” sections of Note 13 for additional information.

ENVIRONMENTAL CONTINGENCIES (Applies to All Registrants except AEPTCo)

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

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

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2020, APCo, OPCo and SWEPCo are named as a Potentially Responsible Party (PRP) for one, three and one sites, respectively, by the Federal EPA for which alleged liability is unresolved. There are 11 additional sites for which APCo, I&M, KPCo, OPCo and SWEPCo received information requests which could lead to PRP designation. I&M has also been named potentially liable at three sites under state law. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2020, management’s estimates do not anticipate material clean-up costs for identified Superfund sites.

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 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. APCo will submit filings with the Virginia SCC and the WVPSC requesting recovery of the respective Virginia and West Virginia jurisdictional shares of these Glen Lyn Station ARO costs. As of December 31, 2020, APCo has not yet incurred any incremental costs associated with the removal of coal combustion material at the Glen Lyn Station.

NUCLEAR CONTINGENCIES (APPLIES TO AEP AND I&M)

I&M owns and operates the two-unit 2,288 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Decommissioning and Low-Level Waste Accumulation Disposal

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2018. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste was $2 billion in 2018 non-discounted dollars, with additional ongoing costs of $6 million per year for post decommissioning storage of SNF and an eventual cost of $37 million for the subsequent decommissioning of the SNF storage facility, also in 2018 non-discounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $4 million, $7 million and $8 million for the years ended December 31, 2020, 2019 and 2018, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2020 and 2019, the total decommissioning trust fund balances were $3 billion and $2.7 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from customers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

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

Spent Nuclear Fuel Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to $0. As of December 31, 2020 and 2019, fees and related interest of $281 million and $280 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Long-term Debt and funds collected from customers along with related earnings totaling $324 million and $323 million, respectively, to pay the fee were recorded as part of Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received $24 million, $8 million and $11 million in 2020, 2019 and 2018, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2022. The proceeds reduced costs for dry cask storage. As of December 31, 2020 and 2019, I&M deferred $14 million and $24 million, respectively, in Prepayments and Other Current Assets and $1 million and $1 million, respectively, in Deferred Charges and Other Noncurrent Assets on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for additional information.

Nuclear Insurance

I&M carries nuclear property insurance of $2.7 billion to cover an incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by an extraordinary incident. Insurance coverage for a nonnuclear property incident at Cook Plant is $500 million. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $42 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $13.8 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $450 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $275 million per nuclear incident on Cook Plant's reactors payable in annual installments of $41 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $450 million through commercially available insurance. The next level of liability coverage of up to $13.3 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

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

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

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

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

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

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

Thereafter, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree. The district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. The consent decree was modified based on an agreement among the parties in July 2019. 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 to plaintiffs' motion for partial summary judgement was filed in October 2020. At the parties' request, the district court stayed the case until February 16, 2021 to provide the parties an opportunity to resolve the case, and the court has since extended the stay until April 26, 2021.

Management will continue to defend against the claims and believes its financial statements appropriately reflect the potential outcome of the pending litigation. The ultimate outcome of the pending litigation could reduce future net income and cash flows and impact financial condition.

Patent Infringement Complaint

In July 2019, Midwest Energy Emissions Corporation and MES Inc. (collectively, the plaintiffs) filed a patent infringement complaint against various parties, including AEP Texas, AGR, Cardinal Operating Company and SWEPCo (collectively, the AEP Defendants). The complaint alleges that the AEP Defendants infringed two patents owned by the plaintiffs by using specific processes for mercury control at certain coal-fired generating stations. The complaint was resolved in December 2020 and did not have a material impact on net income, cash flows or financial condition.

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 is reasonably possible of occurring.

Litigation Related to Ohio House Bill 6 (Applies to AEP and OPCo)

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. The company will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In January 2021, an AEP shareholder filed a derivative action in the United States District Court for the Southern District of Ohio purporting to assert claims on behalf of AEP against certain AEP officers and directors. In February 2021, a second AEP shareholder filed a similar derivative action in the Court of Common Pleas of Franklin County, Ohio. The derivative complaints allege the officers and directors made misrepresentations and omissions similar to those alleged in the putative securities class action lawsuit filed against AEP. The complaints assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets and (c) unjust enrichment and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The company will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

7. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

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

ACQUISITIONS

2020

Santa Rita East (Generation & Marketing Segment)

In November 2020, AEP acquired an additional 10% interest in Santa Rita East for approximately $44 million resulting in AEP having a total interest of 85%. The acquisition of the incremental ownership interest was accounted for as an equity transaction in accordance with the accounting guidance for "Consolidation" and reduced Noncontrolling Interests on the balance sheets by approximately $44 million. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

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. See Note 17 - Variable Interest Entities and Equity Method Investments for additional information.

2019

Sempra Renewables LLC (Generation & Marketing Segment)

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation and battery assets valued at approximately $1.1 billion. This acquisition is part of AEP's strategy to grow its renewable generation portfolio and to diversify generation resources. AEP paid $580 million in cash and acquired a 50% ownership interest in five non-consolidated joint ventures with net assets valued at $404 million as of the acquisition date (which includes $364 million of existing debt obligations). Additionally, the transaction included the acquisition of two tax equity partnerships and the associated recognition of noncontrolling tax equity interest of $135 million.

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

Assets:		**Liabilities and Equity:**		**Net Purchase Price**
		(in millions)		
Current Assets	$ 8.8	Current Liabilities	$ 12.9	
Property, Plant and Equipment	238.1	Asset Retirement Obligations	5.7	
Investment in Joint Ventures	404.0	**Total Liabilities**	18.6	
Other Noncurrent Assets	82.9	Noncontrolling Interest	134.8	
Total Assets	$ 733.8	**Liabilities and Noncontrolling Interest**	$ 153.4	$ 580.4

Management allocated the purchase price based upon the relative fair value of the assets acquired and noncontrolling interests assumed. The fair value of the primary assets acquired and the noncontrolling interests assumed was determined using a discounted cash flow method under the income approach. The key input assumptions utilized in the determination of the fair value of these assets were the pricing and terms of the existing PPAs, forecasted market power prices, expected wind farm net capacity and discount rates reflecting risk inherent in the future cash flows and future power prices. Estimating forecasted market power prices involved determining the cost of constructing and operating a new wind plant over an assumed life in the same geographic region as of the acquisition date using third-party market participant assumptions. The expected wind farm net capacity was developed by evaluating each wind farm's historical and expected generation against historical generation of comparable wind farms in the same locations. Discount rates were evaluated by considering the cost of capital of comparable businesses. Additional key input assumptions for the fair value of the noncontrolling interests include the terms of the limited liability company agreements that dictate the sharing of the tax attributes and cash flows associated with the tax equity partnerships.

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. The PPAs with I&M, OPCo and SWEPCo were executed prior to the acquisition of the wind farms and will be accounted for in accordance with the accounting guidance for "Related Parties." See "Sempra Renewables LLC PPAs" section of Note 16 for additional information.

The acquired business contributed revenues and net income to AEP that were not material for the period April 22, 2019 to December 31, 2019. The pro-forma revenue and net income related to the acquisition of Sempra Renewables LLC were not material for the year ended December 31, 2019.

See Note 17 - Variable Interest Entities and Equity Method Investments for additional information related to the purchased wind farms.

Santa Rita East (Generation & Marketing Segment)

In July 2019, AEP acquired a 75% interest, or 227 MWs, in Santa Rita East for approximately $356 million. In accordance with the accounting guidance for "Business Combinations," management determined that the acquisition of Santa Rita East represents an asset acquisition. Additionally, and in accordance with the accounting guidance for "Consolidation," management concluded that Santa Rita East is a VIE. As a result, to account for the initial consolidation of Santa Rita East, management applied the acquisition method by allocating the purchase price based on the relative fair value of the assets acquired and noncontrolling interest assumed. The fair value of the primary assets acquired and the noncontrolling interest assumed was determined using the market approach. The key input assumptions were the transaction price paid for AEP's interest in Santa Rita East and recent third-party market transactions for similar wind farms. See "Santa Rita East" section of Note 17 for additional information.

DISPOSITIONS

2020

Conesville Plant (Generation & Marketing Segment)

In June 2020, AEP and a nonaffiliated joint-owner executed an Environmental Liability and Property Transfer and Asset Purchase Agreement with a nonaffiliated 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 a total of approximately $98 million over three years, 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 at closing in June 2020 and made an additional payment of $10 million in the fourth quarter of 2020. AEP will make additional payments as detailed in the table below:

	2021	2022
	(in millions)	
First Quarter	$ 9.6	$ 9.6
Second Quarter	9.6	9.6
Third Quarter	9.6	5.2
Fourth Quarter	9.6	—
Total	$ 38.4	$ 24.4

Oklaunion Power Station (Transmission and Distribution Segment and Vertically Integrated Utilities Segment) (Applies to AEP, AEP Texas and PSO)

In October 2020, AEP Texas, PSO and a nonaffiliated joint-owner executed an Environmental Liability and Property Transfer and Asset Purchase Agreement with a nonaffiliated 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 had an immaterial impact on the financial statements in the fourth quarter of 2020.

IMPAIRMENTS

2019

2019 Texas Base Rate Case (Transmission and Distribution Segment) (Applies to AEP and AEP Texas)

In December 2019, AEP Texas recorded a pretax impairment of $33 million in Asset Impairments and Other Related Charges on the statements of income due to regulatory disallowances in the 2019 Texas Base Rate Case. See "2019 Texas Base Rate Case" section of Note 4 for additional information.

Virginia Jurisdictional Book Value of Retired Coal-Fired Plants (Vertically Integrated Utilities Segment) (Applies to AEP and APCo)

In December 2019, based on management's interpretation of Virginia law and more certainty regarding APCo's triennial revenues, expenses and resulting earnings upon reaching the end of the three-year review period, APCo recorded a pretax expense of $93 million in Asset Impairments and Other Related Charges on the statements of income related to its previously retired coal-fired generation. As a result, management deemed these costs to be substantially recovered by APCo during the triennial review period. See "2017-2019 Virginia Triennial Review" section of Note 4 for additional information.

Merchant Generating Assets (Generation & Marketing Segment)

Due to a significant increase in the asset retirement costs recorded in December 2019 for the Ash Pond Complex at Conesville Plant, AEP performed an impairment analysis on Conesville Plant in accordance with accounting guidance for impairments of long-lived assets. AEP performed step one and step two of the impairment analysis using a cash flow model for the estimated useful life of Conesville Plant based upon energy and capacity price curves, which were developed internally with both observable Level 2 third-party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses. The step two analysis resulted in a fair value determination for Conesville Plant of $0 and AEP recorded a $31 million pretax impairment, equal to the net book value of the plant, in Asset Impairments and Other Related Charges on AEP's statements of income in the fourth quarter of 2019.

2018

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

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

Merchant Generating Assets (Generation & Marketing Segment)

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017 and reconstruction activities continued throughout 2018. AEP initially impaired Racine in 2017 as discussed in the "2017 Merchant Generating Assets" section of the Acquisitions, Dispositions and Impairments Note within the 2019 Annual Report.

Through the third quarter of 2018, the Racine reconstruction project had accumulated new capital expenditures of $35 million. Due to a significant increase in estimated costs to complete the reconstruction project, an impairment analysis was performed. AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful life of Racine based upon energy and capacity price curves, which were developed internally with observable Level 2 third-party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. AEP performed step two of the impairment analysis on Racine using a ten-year discounted cash flow model based upon similar forecasted information used in the step one test. The step two analysis resulted in a determination that the fair value of Racine in its condition as of September 30, 2018 was $0. As a result, AEP recorded a pretax impairment of $35 million in Other Operation on the statements of income in the third quarter of 2018. In October 2018, AEP received authorization from the FERC to restart generation at Racine and generation resumed in November 2018. Reconstruction activities at Racine were completed in 2020.

8. BENEFIT PLANS

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

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

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

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

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

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		OPEB	
	December 31,			
Assumption	2020	2019	2020	2019
Discount Rate	2.50 %	3.25 %	2.55 %	3.30 %
Interest Crediting Rate	4.00 %	4.00 %	NA	NA

NA Not applicable.

	Pension Plans	
	December 31,	
Assumption – Rate of Compensation Increase (a)	2020	2019
AEP	5.00 %	4.95 %
AEP Texas	5.05 %	5.00 %
APCo	4.85 %	4.80 %
I&M	5.00 %	4.95 %
OPCo	5.25 %	5.15 %
PSO	5.05 %	5.05 %
SWEPCo	4.90 %	4.90 %

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

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

For 2020, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrants' population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			OPEB		
	Year Ended December 31,					
Assumption	**2020**	**2019**	**2018**	**2020**	**2019**	**2018**
Discount Rate	3.25 %	4.30 %	3.65 %	3.30 %	4.30 %	3.60 %
Interest Crediting Rate	4.00 %	4.00 %	4.00 %	NA	NA	NA
Expected Return on Plan Assets	5.75 %	6.25 %	6.00 %	5.50 %	6.25 %	6.00 %

NA Not applicable.

	Pension Plans		
	Year Ended December 31,		
Assumption – Rate of Compensation Increase (a)	**2020**	**2019**	**2018**
AEP	5.00 %	4.95 %	4.85 %
AEP Texas	5.05 %	5.00 %	4.95 %
APCo	4.85 %	4.75 %	4.75 %
I&M	5.00 %	4.95 %	4.90 %
OPCo	5.25 %	5.20 %	5.00 %
PSO	5.05 %	5.05 %	4.90 %
SWEPCo	4.90 %	4.90 %	4.85 %

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

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

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

	December 31,	
Health Care Trend Rates	**2020**	**2019**
Initial	6.50 %	6.00 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2029	2026

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2020, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets, Funded Status and Amounts Recognized on the Balance Sheets

For the year ended December 31, 2020, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, partially offset by a decrease in the assumed rate used to convert account balances to annuities. For the year ended December 31, 2020, the OPEB plans had an actuarial loss primarily due to a decrease in the discount rate and an update to the health care trend assumption, partially offset by updated projected per capita claims costs due to rate negotiations for Medicare advantage premium rates. For the year ended December 31, 2019, the pension plans had an actuarial loss due to a decrease in the discount rate, partially offset by updates to the mortality table. For the year ended December 31, 2019, the OPEB plans had an actuarial loss due to a decrease in the discount rate and an update to the persistency assumption, partially offset by an update to the projected per capita cost assumption as well as savings resulting from legislation signed in December 2019 which eliminated two Affordable Care Act taxes. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

AEP	Pension Plans		OPEB	
	2020	2019	2020	2019
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 5,236.8	$ 4,810.3	$ 1,225.4	$ 1,194.5
Service Cost	111.9	95.5	10.0	9.5
Interest Cost	167.9	204.4	39.8	50.5
Actuarial Loss	434.7	493.6	39.3	58.8
Plan Amendments	—	0.2	(11.4)	(11.0)
Benefit Payments	(406.8)	(367.2)	(131.0)	(113.0)
Participant Contributions	—	—	38.2	35.5
Medicare Subsidy	—	—	0.6	0.6
Benefit Obligation as of December 31,	$ 5,544.5	$ 5,236.8	$ 1,210.9	$ 1,225.4
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 5,015.4	$ 4,695.9	$ 1,781.8	$ 1,534.2
Actual Gain on Plan Assets	832.4	681.1	253.0	321.0
Company Contributions (a)	115.6	5.6	4.7	4.1
Participant Contributions	—	—	38.2	35.5
Benefit Payments	(406.8)	(367.2)	(131.0)	(113.0)
Fair Value of Plan Assets as of December 31,	$ 5,556.6	$ 5,015.4	$ 1,946.7	$ 1,781.8
Funded (Underfunded) Status as of December 31,	$ 12.1	$ (221.4)	$ 735.8	$ 556.4

(a) Contributions to the qualified pension plan were $110 million and $0 for the years ended December 31, 2020 and 2019, respectively. Contributions to the non-qualified pension plans were $6 million and $6 million for the years ended December 31, 2020 and 2019, respectively.

AEP	Pension Plans 2020	Pension Plans 2019	OPEB 2020	OPEB 2019
	December 31,			
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 93.5	$ —	$ 771.9	$ 590.8
Other Current Liabilities – Accrued Short-term Benefit Liability	(6.7)	(6.1)	(2.4)	(2.6)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(74.7)	(215.3)	(33.7)	(31.8)
Funded (Underfunded) Status	$ 12.1	$ (221.4)	$ 735.8	$ 556.4

AEP Texas	Pension Plans 2020	Pension Plans 2019	OPEB 2020	OPEB 2019
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 441.2	$ 409.3	$ 97.8	$ 95.9
Service Cost	10.0	8.6	0.8	0.8
Interest Cost	13.9	17.5	3.2	4.0
Actuarial Loss	28.1	40.1	2.4	3.9
Plan Amendments	—	—	(1.0)	(0.9)
Benefit Payments	(40.0)	(34.3)	(10.0)	(8.8)
Participant Contributions	—	—	3.1	2.9
Benefit Obligation as of December 31,	$ 453.2	$ 441.2	$ 96.3	$ 97.8
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 435.1	$ 410.7	$ 148.1	$ 129.9
Actual Gain on Plan Assets	67.2	58.3	21.1	24.0
Company Contributions	11.7	0.4	—	0.1
Participant Contributions	—	—	3.1	2.9
Benefit Payments	(40.0)	(34.3)	(10.0)	(8.8)
Fair Value of Plan Assets as of December 31,	$ 474.0	$ 435.1	$ 162.3	$ 148.1
Funded (Underfunded) Status as of December 31,	$ 20.8	$ (6.1)	$ 66.0	$ 50.3

AEP Texas	Pension Plans 2020	Pension Plans 2019	OPEB 2020	OPEB 2019
	December 31,			
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 24.7	$ —	$ 66.0	$ 50.3
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.4)	(0.4)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(3.5)	(5.7)	—	—
Funded (Underfunded) Status	$ 20.8	$ (6.1)	$ 66.0	$ 50.3

APCo	Pension Plans		OPEB	
	2020	2019	2020	2019
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 647.2	$ 603.1	$ 203.5	$ 205.5
Service Cost	10.5	9.4	1.0	1.0
Interest Cost	20.3	25.2	6.6	8.7
Actuarial Loss	40.0	52.9	5.6	4.7
Plan Amendments	—	—	(1.8)	(1.7)
Benefit Payments	(47.2)	(43.4)	(23.2)	(20.8)
Participant Contributions	—	—	6.3	5.9
Medicare Subsidy	—	—	0.2	0.2
Benefit Obligation as of December 31,	$ 670.8	$ 647.2	$ 198.2	$ 203.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 637.0	$ 593.3	$ 271.0	$ 238.4
Actual Gain on Plan Assets	104.5	87.1	36.8	45.3
Company Contributions	7.0	—	2.1	2.2
Participant Contributions	—	—	6.3	5.9
Benefit Payments	(47.2)	(43.4)	(23.2)	(20.8)
Fair Value of Plan Assets as of December 31,	$ 701.3	$ 637.0	$ 293.0	$ 271.0
Funded (Underfunded) Status as of December 31,	$ 30.5	$ (10.2)	$ 94.8	$ 67.5

	Pension Plans		OPEB	
	December 31,			
APCo	2020	2019	2020	2019
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 31.0	$ —	$ 119.1	$ 92.0
Other Current Liabilities – Accrued Short-term Benefit Liability	—	—	(1.8)	(2.0)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(0.5)	(10.2)	(22.5)	(22.5)
Funded (Underfunded) Status	$ 30.5	$ (10.2)	$ 94.8	$ 67.5

I&M	Pension Plans		OPEB	
	2020	2019	2020	2019
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 616.1	$ 567.0	$ 142.9	$ 138.3
Service Cost	15.4	13.4	1.4	1.4
Interest Cost	19.7	23.8	4.7	5.8
Actuarial Loss	44.3	49.8	5.1	8.1
Plan Amendments	—	—	(1.6)	(1.5)
Benefit Payments	(42.2)	(37.9)	(15.9)	(13.6)
Participant Contributions	—	—	4.8	4.4
Benefit Obligation as of December 31,	$ 653.3	$ 616.1	$ 141.4	$ 142.9
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 630.5	$ 583.8	$ 216.3	$ 187.3
Actual Gain on Plan Assets	103.3	84.6	33.0	38.2
Company Contributions	6.5	—	—	—
Participant Contributions	—	—	4.8	4.4
Benefit Payments	(42.2)	(37.9)	(15.9)	(13.6)
Fair Value of Plan Assets as of December 31,	$ 698.1	$ 630.5	$ 238.2	$ 216.3
Funded Status as of December 31,	$ 44.8	$ 14.4	$ 96.8	$ 73.4

	Pension Plans		OPEB	
	December 31,			
I&M	2020	2019	2020	2019
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 46.5	$ 15.8	$ 96.8	$ 73.4
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.7)	(1.4)	—	—
Funded Status	$ 44.8	$ 14.4	$ 96.8	$ 73.4

OPCo	Pension Plans		OPEB	
	2020	2019	2020	2019
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 487.8	$ 453.9	$ 130.2	$ 129.5
Service Cost	9.7	7.9	0.9	0.8
Interest Cost	15.4	19.1	4.2	5.5
Actuarial Loss	33.4	40.5	3.1	4.9
Plan Amendments	—	—	(1.3)	(1.2)
Benefit Payments	(36.0)	(33.6)	(15.0)	(13.5)
Participant Contributions	—	—	4.3	4.1
Medicare Subsidy	—	—	—	0.1
Benefit Obligation as of December 31,	$ 510.3	$ 487.8	$ 126.4	$ 130.2
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 499.1	$ 466.1	$ 197.1	$ 175.4
Actual Gain on Plan Assets	79.9	66.6	26.6	31.1
Company Contributions	0.1	—	—	—
Participant Contributions	—	—	4.3	4.1
Benefit Payments	(36.0)	(33.6)	(15.0)	(13.5)
Fair Value of Plan Assets as of December 31,	$ 543.1	$ 499.1	$ 213.0	$ 197.1
Funded Status as of December 31,	$ 32.8	$ 11.3	$ 86.6	$ 66.9

	Pension Plans		OPEB	
	December 31,			
OPCo	2020	2019	2020	2019
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 33.3	$ 11.7	$ 86.6	$ 66.9
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(0.5)	(0.4)	—	—
Funded Status	$ 32.8	$ 11.3	$ 86.6	$ 66.9

PSO	Pension Plans		OPEB	
	2020	2019	2020	2019
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 267.5	$ 253.8	$ 64.7	$ 62.3
Service Cost	7.3	6.5	0.7	0.6
Interest Cost	8.5	10.6	2.1	2.6
Actuarial Loss	17.7	16.8	1.9	3.8
Plan Amendments	—	—	(0.7)	(0.7)
Benefit Payments	(21.1)	(20.2)	(6.8)	(5.9)
Participant Contributions	—	—	2.1	2.0
Benefit Obligation as of December 31,	$ 279.9	$ 267.5	$ 64.0	$ 64.7
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 276.2	$ 261.2	$ 98.0	$ 84.3
Actual Gain on Plan Assets	44.6	34.7	14.5	17.6
Company Contributions	0.1	0.5	—	—
Participant Contributions	—	—	2.1	2.0
Benefit Payments	(21.1)	(20.2)	(6.8)	(5.9)
Fair Value of Plan Assets as of December 31,	$ 299.8	$ 276.2	$ 107.8	$ 98.0
Funded Status as of December 31,	$ 19.9	$ 8.7	$ 43.8	$ 33.3

PSO	Pension Plans		OPEB	
	December 31,			
	2020	2019	2020	2019
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 21.9	$ 10.6	$ 43.8	$ 33.3
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.1)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.9)	(1.8)	—	—
Funded Status	$ 19.9	$ 8.7	$ 43.8	$ 33.3

SWEPCo

Change in Benefit Obligation	Pension Plans 2020	Pension Plans 2019	OPEB 2020	OPEB 2019
	(in millions)			
Benefit Obligation as of January 1,	$ 314.2	$ 291.4	$ 77.4	$ 72.7
Service Cost	9.9	8.6	0.8	0.8
Interest Cost	10.2	12.4	2.5	3.1
Actuarial Loss	27.4	25.5	2.5	6.0
Plan Amendments	—	—	(0.8)	(0.8)
Benefit Payments	(27.2)	(23.7)	(7.7)	(6.6)
Participant Contributions	—	—	2.4	2.2
Benefit Obligation as of December 31,	$ 334.5	$ 314.2	$ 77.1	$ 77.4
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 296.9	$ 281.0	$ 117.2	$ 98.5
Actual Gain on Plan Assets	48.2	39.5	18.0	23.1
Company Contributions	9.0	0.1	—	—
Participant Contributions	—	—	2.4	2.2
Benefit Payments	(27.2)	(23.7)	(7.7)	(6.6)
Fair Value of Plan Assets as of December 31,	$ 326.9	$ 296.9	$ 129.9	$ 117.2
Funded (Underfunded) Status as of December 31,	$ (7.6)	$ (17.3)	$ 52.8	$ 39.8

SWEPCo	Pension Plans 2020	Pension Plans 2019	OPEB 2020	OPEB 2019
	December 31, (in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 52.8	$ 39.8
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.1)	(0.1)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(7.5)	(17.2)	—	—
Funded (Underfunded) Status	$ (7.6)	$ (17.3)	$ 52.8	$ 39.8

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in Regulatory Assets, Deferred Income Taxes and AOCI and the items attributable to the change in these components:

AEP	**Pension Plans**		**OPEB**	
	December 31,			
	2020	**2019**	**2020**	**2019**
Components	**(in millions)**			
Net Actuarial Loss	$ 1,179.6	$ 1,406.2	$ 101.9	$ 225.8
Prior Service Cost (Credit)	0.2	0.2	(227.3)	(285.7)
Recorded as				
Regulatory Assets	$ 1,182.4	$ 1,351.8	$ (99.0)	$ (46.8)
Deferred Income Taxes	(0.5)	11.5	(5.5)	(2.7)
Net of Tax AOCI	(2.1)	43.1	(20.9)	(10.4)

AEP	**Pension Plans**		**OPEB**	
	2020	**2019**	**2020**	**2019**
Components	**(in millions)**			
Actuarial (Gain) Loss During the Year	$ (132.9)	$ 108.6	$ (118.0)	$ (171.9)
Amortization of Actuarial Loss	(93.7)	(57.6)	(5.9)	(22.1)
Prior Service (Credit) Cost	—	0.2	(11.4)	(7.6)
Amortization of Prior Service Credit	—	—	69.8	69.1
Change for the Year Ended December 31,	$ (226.6)	$ 51.2	$ (65.5)	$ (132.5)

AEP Texas	**Pension Plans**		**OPEB**	
	December 31,			
	2020	**2019**	**2020**	**2019**
Components	**(in millions)**			
Net Actuarial Loss	$ 160.5	$ 184.7	$ 12.3	$ 23.5
Prior Service Credit	—	—	(19.3)	(24.2)
Recorded as				
Regulatory Assets	$ 151.3	$ 172.2	$ (6.3)	$ (0.2)
Deferred Income Taxes	2.0	2.7	(0.1)	(0.1)
Net of Tax AOCI	7.2	9.8	(0.6)	(0.4)

AEP Texas	**Pension Plans**		**OPEB**	
	2020	**2019**	**2020**	**2019**
Components	**(in millions)**			
Actuarial (Gain) Loss During the Year	$ (16.4)	$ 7.6	$ (10.7)	$ (12.7)
Amortization of Actuarial Loss	(7.8)	(4.9)	(0.5)	(1.8)
Prior Service Credit	—	—	(1.0)	(0.6)
Amortization of Prior Service Credit	—	—	5.9	5.9
Change for the Year Ended December 31,	$ (24.2)	$ 2.7	$ (6.3)	$ (9.2)

APCo	Pension Plans		OPEB	
	December 31,			
	2020	2019	2020	2019
Components	(in millions)			
Net Actuarial Loss	$ 126.3	$ 168.3	$ 11.1	$ 28.8
Prior Service Credit	—	—	(33.2)	(41.6)
Recorded as				
Regulatory Assets	$ 124.7	$ 166.3	$ (10.3)	$ (5.5)
Deferred Income Taxes	0.3	0.3	(2.5)	(1.5)
Net of Tax AOCI	1.3	1.7	(9.3)	(5.8)

APCo	Pension Plans		OPEB	
	2020	2019	2020	2019
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (30.8)	$ 3.1	$ (16.8)	$ (26.4)
Amortization of Actuarial Loss	(11.2)	(7.0)	(0.9)	(3.7)
Prior Service Credit	—	—	(1.8)	(1.3)
Amortization of Prior Service Credit	—	—	10.2	10.1
Change for the Year Ended December 31,	$ (42.0)	$ (3.9)	$ (9.3)	$ (21.3)

I&M	Pension Plans		OPEB	
	December 31,			
	2020	2019	2020	2019
Components	(in millions)			
Net Actuarial Loss	$ 39.5	$ 76.0	$ 15.6	$ 32.7
Prior Service Credit	—	—	(31.0)	(39.0)
Recorded as				
Regulatory Assets	$ 40.3	$ 73.7	$ (14.6)	$ (6.2)
Deferred Income Taxes	(0.1)	0.5	(0.2)	—
Net of Tax AOCI	(0.7)	1.8	(0.6)	(0.1)

I&M	Pension Plans		OPEB	
	2020	2019	2020	2019
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (25.7)	$ 2.0	$ (16.4)	$ (19.3)
Amortization of Actuarial Loss	(10.8)	(6.6)	(0.7)	(2.7)
Prior Service Credit	—	—	(1.5)	(1.0)
Amortization of Prior Service Credit	—	—	9.5	9.4
Change for the Year Ended December 31,	$ (36.5)	$ (4.6)	$ (9.1)	$ (13.6)

OPCo	Pension Plans		OPEB	
	December 31,			
	2020	2019	2020	2019
Components	(in millions)			
Net Actuarial Loss	$ 150.0	$ 178.7	$ 3.6	$ 17.2
Prior Service Credit	—	—	(22.9)	(28.6)
Recorded as				
Regulatory Assets	$ 150.0	$ 178.7	$ (19.3)	$ (11.4)

OPCo	Pension Plans		OPEB	
	2020	2019	2020	2019
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (20.2)	$ 3.3	$ (12.9)	$ (15.8)
Amortization of Actuarial Loss	(8.5)	(5.3)	(0.7)	(2.5)
Prior Service Credit	—	—	(1.3)	(0.8)
Amortization of Prior Service Credit	—	—	7.0	6.9
Change for the Year Ended December 31,	$ (28.7)	$ (2.0)	$ (7.9)	$ (12.2)

PSO	Pension Plans		OPEB	
	December 31,			
	2020	2019	2020	2019
Components	(in millions)			
Net Actuarial Loss	$ 55.9	$ 73.0	$ 10.5	$ 18.2
Prior Service Credit	—	—	(14.1)	(17.8)
Recorded as				
Regulatory Assets	$ 55.9	$ 73.0	$ (3.6)	$ 0.4

PSO	Pension Plans		OPEB	
	2020	2019	2020	2019
Components	(in millions)			
Actuarial Gain During the Year	$ (12.4)	$ (1.7)	$ (7.4)	$ (8.9)
Amortization of Actuarial Loss	(4.7)	(2.9)	(0.3)	(1.2)
Prior Service Credit	—	—	(0.7)	(0.5)
Amortization of Prior Service Credit	—	—	4.4	4.3
Change for the Year Ended December 31,	$ (17.1)	$ (4.6)	$ (4.0)	$ (6.3)

SWEPCo	Pension Plans		OPEB	
	December 31,			
	2020	2019	2020	2019
Components	(in millions)			
Net Actuarial Loss	$ 86.9	$ 97.8	$ 11.5	$ 21.1
Prior Service Credit	—	—	(17.2)	(21.6)
Recorded as				
Regulatory Assets	$ 86.9	$ 97.8	$ (3.0)	$ —
Deferred Income Taxes	—	—	(0.5)	—
Net of Tax AOCI	—	—	(2.2)	(0.5)

SWEPCo	Pension Plans		OPEB	
	2020	2019	2020	2019
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (5.2)	$ 3.8	$ (9.2)	$ (11.4)
Amortization of Actuarial Loss	(5.7)	(3.4)	(0.4)	(1.4)
Prior Service Credit	—	—	(0.8)	(0.6)
Amortization of Prior Service Credit	—	—	5.2	5.2
Change for the Year Ended December 31,	$ (10.9)	$ 0.4	$ (5.2)	$ (8.2)

Determination of Pension Expense

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

Pension and OPEB Assets

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

	Pension Plan		OPEB	
	December 31,			
Company	2020	2019	2020	2019
AEP Texas	8.5 %	8.7 %	8.3 %	8.3 %
APCo	12.6 %	12.7 %	15.1 %	15.2 %
I&M	12.6 %	12.6 %	12.2 %	12.1 %
OPCo	9.8 %	10.0 %	10.9 %	11.1 %
PSO	5.4 %	5.5 %	5.5 %	5.5 %
SWEPCo	5.9 %	5.9 %	6.7 %	6.6 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2020:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 542.3	$ —	$ —	$ —	$ 542.3	9.7 %
International	676.3	—	—	—	676.3	12.2 %
Common Collective Trusts (c)	—	—	—	650.0	650.0	11.7 %
Subtotal – Equities	1,218.6	—	—	650.0	1,868.6	33.6 %
Fixed Income (a):						
United States Government and Agency Securities	(1.4)	1,134.1	—	—	1,132.7	20.4 %
Corporate Debt	—	1,425.0	—	—	1,425.0	25.6 %
Foreign Debt	—	214.0	—	—	214.0	3.9 %
State and Local Government	—	56.0	—	—	56.0	1.0 %
Other – Asset Backed	—	0.8	—	—	0.8	— %
Subtotal – Fixed Income	(1.4)	2,829.9	—	—	2,828.5	50.9 %
Infrastructure (c)	—	—	—	91.1	91.1	1.6 %
Real Estate (c)	—	—	—	231.6	231.6	4.2 %
Alternative Investments (c)	—	—	—	431.8	431.8	7.8 %
Cash and Cash Equivalents (c)	—	49.3	—	58.2	107.5	1.9 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(2.5)	(2.5)	— %
Total	$ 1,217.2	$ 2,879.2	$ —	$ 1,460.2	$ 5,556.6	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2020:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 399.9	$ —	$ —	$ —	$ 399.9	20.6 %
International	290.7	—	—	—	290.7	14.9 %
Common Collective Trusts (b)	—	—	—	264.7	264.7	13.6 %
Subtotal – Equities	690.6	—	—	264.7	955.3	49.1 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	186.4	186.4	9.6 %
United States Government and Agency Securities	(0.2)	199.7	—	—	199.5	10.2 %
Corporate Debt	—	248.7	—	—	248.7	12.8 %
Foreign Debt	—	34.9	—	—	34.9	1.8 %
State and Local Government	73.9	13.1	—	—	87.0	4.5 %
Subtotal – Fixed Income	73.7	496.4	—	186.4	756.5	38.9 %
Trust Owned Life Insurance:						
International Equities	—	64.8	—	—	64.8	3.3 %
United States Bonds	—	135.9	—	—	135.9	7.0 %
Subtotal – Trust Owned Life Insurance	—	200.7	—	—	200.7	10.3 %
Cash and Cash Equivalents (b)	26.3	—	—	5.7	32.0	1.6 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	2.2	2.2	0.1 %
Total	$ 790.6	$ 697.1	$ —	$ 459.0	$ 1,946.7	100.0 %

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

(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per-share.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 387.8	$ —	$ —	$ —	$ 387.8	7.8 %
International	609.1	—	—	—	609.1	12.1 %
Common Collective Trusts (c)	—	—	—	547.3	547.3	10.9 %
Subtotal – Equities	996.9	—	—	547.3	1,544.2	30.8 %
Fixed Income (a):						
United States Government and Agency Securities	(5.8)	1,248.6	—	—	1,242.8	24.8 %
Corporate Debt	—	1,143.7	—	—	1,143.7	22.8 %
Foreign Debt	—	211.6	—	—	211.6	4.2 %
State and Local Government	—	55.1	—	—	55.1	1.1 %
Other – Asset Backed	—	3.6	—	—	3.6	0.1 %
Subtotal – Fixed Income	(5.8)	2,662.6	—	—	2,656.8	53.0 %
Infrastructure (c)	—	—	—	85.8	85.8	1.7 %
Real Estate (c)	—	—	—	239.4	239.4	4.8 %
Alternative Investments (c)	—	—	—	448.3	448.3	8.9 %
Cash and Cash Equivalents (c)	—	24.4	—	37.2	61.6	1.2 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(20.7)	(20.7)	(0.4)%
Total	$ 991.1	$ 2,687.0	$ —	$ 1,337.3	$ 5,015.4	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 312.2	$ —	$ —	$ —	$ 312.2	17.5 %
International	251.5	—	—	—	251.5	14.1 %
Common Collective Trusts (b)	—	—	—	260.8	260.8	14.7 %
Subtotal – Equities	563.7	—	—	260.8	824.5	46.3 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	177.6	177.6	10.0 %
United States Government and Agency Securities	(0.1)	214.4	—	—	214.3	12.0 %
Corporate Debt	—	206.7	—	—	206.7	11.6 %
Foreign Debt	—	35.5	—	—	35.5	2.0 %
State and Local Government	58.8	14.8	—	—	73.6	4.1 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	58.7	471.6	—	177.6	707.9	39.7 %
Trust Owned Life Insurance:						
International Equities	—	60.2	—	—	60.2	3.4 %
United States Bonds	—	151.6	—	—	151.6	8.5 %
Subtotal – Trust Owned Life Insurance	—	211.8	—	—	211.8	11.9 %
Cash and Cash Equivalents (b)	26.7	—	—	6.7	33.4	1.9 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	4.2	4.2	0.2 %
Total	$ 649.1	$ 683.4	$ —	$ 449.3	$ 1,781.8	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.

Accumulated Benefit Obligation

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

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 5,171.3	$ 424.5	$ 645.8	$ 615.8	$ 479.2	$ 258.3	$ 307.1
Nonqualified Pension Plans	72.9	3.6	0.2	0.8	0.2	1.6	1.4
Total as of December 31, 2020	$ 5,244.2	$ 428.1	$ 646.0	$ 616.6	$ 479.4	$ 259.9	$ 308.5

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,929.0	$ 417.5	$ 627.3	$ 586.3	$ 464.2	$ 248.9	$ 291.9
Nonqualified Pension Plans	69.7	3.6	0.2	0.6	0.1	1.6	1.3
Total as of December 31, 2019	$ 4,998.7	$ 421.1	$ 627.5	$ 586.9	$ 464.3	$ 250.5	$ 293.2

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 81.4	$ 3.9	$ 0.5	$ 1.7	$ 0.6	$ 2.0	$ 334.5
Fair Value of Plan Assets	—	—	—	—	—	—	326.9
Underfunded Projected Benefit Obligation as of December 31, 2020	$ (81.4)	$ (3.9)	$ (0.5)	$ (1.7)	$ (0.6)	$ (2.0)	$ (7.6)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 5,236.8	$ 441.2	$ 647.2	$ 1.5	$ 0.4	$ 1.9	$ 314.2
Fair Value of Plan Assets	5,015.4	435.1	637.0	—	—	—	296.9
Underfunded Projected Benefit Obligation as of December 31, 2019	$ (221.4)	$ (6.1)	$ (10.2)	$ (1.5)	$ (0.4)	$ (1.9)	$ (17.3)

Accumulated Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 72.9	$ 3.6	$ 0.2	$ 0.8	$ 0.2	$ 1.6	$ 1.4
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2020	$ (72.9)	$ (3.6)	$ (0.2)	$ (0.8)	$ (0.2)	$ (1.6)	$ (1.4)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 69.7	$ 3.6	$ 0.2	$ 0.6	$ 0.1	$ 1.6	$ 1.3
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2019	$ (69.7)	$ (3.6)	$ (0.2)	$ (0.6)	$ (0.1)	$ (1.6)	$ (1.3)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded non-qualified benefits. For the qualified pension plan, additional discretionary contributions may also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant for 2021:

Company	Pension Plans	OPEB
	(in millions)	
AEP	$ 132.8	$ 3.1
AEP Texas	5.1	0.1
APCo	1.8	1.8
I&M	1.3	—
PSO	0.1	—
SWEPCo	7.1	—

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

Pension Plans	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2021	$ 385.3	$ 36.3	$ 44.7	$ 40.2	$ 35.4	$ 21.8	$ 25.2
2022	382.8	35.9	45.1	42.4	36.0	21.2	25.4
2023	384.3	36.1	45.1	41.5	34.2	22.3	25.7
2024	384.0	35.9	45.7	42.7	34.0	21.9	25.7
2025	377.1	35.2	44.0	42.7	33.3	21.1	25.3
Years 2026 to 2030, in Total	1,763.1	154.1	209.7	205.2	155.0	94.8	115.7

OPEB Benefit Payments	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2021	$ 121.6	$ 9.5	$ 21.1	$ 15.1	$ 13.7	$ 6.4	$ 7.5
2022	122.5	9.9	20.8	15.3	13.9	6.7	7.8
2023	117.4	9.7	19.8	14.7	13.2	6.6	7.6
2024	121.9	10.3	20.5	15.3	13.7	6.9	8.2
2025	120.9	10.4	20.0	15.1	13.4	6.9	8.2
Years 2026 to 2030, in Total	573.9	48.6	93.3	70.9	61.7	32.1	39.1

OPEB Medicare Subsidy Receipts	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
2021	$ 0.2	$ —	$ 0.1	$ —	$ —	$ —	$ —
2022	0.2	—	0.1	—	—	—	—
2023	0.3	—	0.1	—	—	—	—
2024	0.3	—	0.1	—	—	—	—
2025	0.3	—	0.1	—	—	—	—
Years 2026 to 2030, in Total	1.5	—	0.6	—	—	—	—

Components of Net Periodic Benefit Cost

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

AEP	Pension Plans			OPEB		
	Years Ended December 31,					
	2020	2019	2018	2020	2019	2018
	(in millions)					
Service Cost	$ 111.9	$ 95.5	$ 97.6	$ 10.0	$ 9.5	$ 11.6
Interest Cost	167.9	204.4	187.8	39.8	50.5	47.4
Expected Return on Plan Assets	(264.9)	(296.0)	(290.3)	(95.6)	(93.7)	(102.2)
Amortization of Prior Service Credit	—	—	—	(69.8)	(69.1)	(69.1)
Amortization of Net Actuarial Loss	93.7	57.6	85.2	5.9	22.1	10.5
Settlements	—	—	2.6	—	—	—
Net Periodic Benefit Cost (Credit)	108.6	61.5	82.9	(109.7)	(80.7)	(101.8)
Capitalized Portion	(47.0)	(38.6)	(41.1)	(4.2)	(3.8)	(4.9)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 61.6	$ 22.9	$ 41.8	$ (113.9)	$ (84.5)	$ (106.7)

AEP Texas	**Pension Plans**			**OPEB**		
	Years Ended December 31,					
	2020	**2019**	**2018**	**2020**	**2019**	**2018**
	(in millions)					
Service Cost	$ 10.0	$ 8.6	$ 9.2	$ 0.8	$ 0.8	$ 0.9
Interest Cost	13.9	17.5	16.0	3.2	4.0	3.8
Expected Return on Plan Assets	(22.7)	(25.8)	(25.6)	(8.0)	(7.8)	(8.6)
Amortization of Prior Service Credit	—	—	—	(5.9)	(5.9)	(5.9)
Amortization of Net Actuarial Loss	7.8	4.9	7.2	0.5	1.8	0.8
Net Periodic Benefit Cost (Credit)	9.0	5.2	6.8	(9.4)	(7.1)	(9.0)
Capitalized Portion	(5.5)	(4.5)	(4.8)	(0.4)	(0.4)	(0.5)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.5	$ 0.7	$ 2.0	$ (9.8)	$ (7.5)	$ (9.5)

APCo	**Pension Plans**			**OPEB**		
	Years Ended December 31,					
	2020	**2019**	**2018**	**2020**	**2019**	**2018**
	(in millions)					
Service Cost	$ 10.5	$ 9.4	$ 9.3	$ 1.0	$ 1.0	$ 1.1
Interest Cost	20.3	25.2	23.5	6.6	8.7	8.2
Expected Return on Plan Assets	(33.6)	(37.4)	(36.6)	(14.4)	(14.6)	(16.0)
Amortization of Prior Service Credit	—	—	—	(10.2)	(10.1)	(10.0)
Amortization of Net Actuarial Loss	11.2	7.0	10.6	0.9	3.7	1.9
Net Periodic Benefit Cost (Credit)	8.4	4.2	6.8	(16.1)	(11.3)	(14.8)
Capitalized Portion	(4.5)	(4.0)	(3.8)	(0.4)	(0.4)	(0.5)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.9	$ 0.2	$ 3.0	$ (16.5)	$ (11.7)	$ (15.3)

I&M	**Pension Plans**			**OPEB**		
	Years Ended December 31,					
	2020	**2019**	**2018**	**2020**	**2019**	**2018**
	(in millions)					
Service Cost	$ 15.4	$ 13.4	$ 13.6	$ 1.4	$ 1.4	$ 1.6
Interest Cost	19.7	23.8	22.1	4.7	5.8	5.4
Expected Return on Plan Assets	(33.3)	(36.8)	(35.7)	(11.7)	(11.4)	(12.3)
Amortization of Prior Service Credit	—	—	—	(9.5)	(9.4)	(9.5)
Amortization of Net Actuarial Loss	10.8	6.6	9.8	0.7	2.7	1.2
Net Periodic Benefit Cost (Credit)	12.6	7.0	9.8	(14.4)	(10.9)	(13.6)
Capitalized Portion	(4.3)	(3.4)	(5.6)	(0.4)	(0.4)	(0.7)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 8.3	$ 3.6	$ 4.2	$ (14.8)	$ (11.3)	$ (14.3)

OPCo	Pension Plans			OPEB		
	Years Ended December 31,					
	2020	2019	2018	2020	2019	2018
	(in millions)					
Service Cost	$ 9.7	$ 7.9	$ 7.7	$ 0.9	$ 0.8	$ 0.9
Interest Cost	15.4	19.1	17.7	4.2	5.5	5.1
Expected Return on Plan Assets	(26.3)	(29.3)	(28.8)	(10.5)	(10.8)	(11.7)
Amortization of Prior Service Credit	—	—	—	(7.0)	(6.9)	(6.9)
Amortization of Net Actuarial Loss	8.5	5.3	8.0	0.7	2.5	1.1
Net Periodic Benefit Cost (Credit)	7.3	3.0	4.6	(11.7)	(8.9)	(11.5)
Capitalized Portion	(5.0)	(3.7)	(3.6)	(0.5)	(0.4)	(0.4)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 2.3	$ (0.7)	$ 1.0	$ (12.2)	$ (9.3)	$ (11.9)

PSO	Pension Plans			OPEB		
	Years Ended December 31,					
	2020	2019	2018	2020	2019	2018
	(in millions)					
Service Cost	$ 7.3	$ 6.5	$ 7.0	$ 0.7	$ 0.6	$ 0.7
Interest Cost	8.5	10.6	9.9	2.1	2.6	2.5
Expected Return on Plan Assets	(14.5)	(16.3)	(16.1)	(5.2)	(5.1)	(5.6)
Amortization of Prior Service Credit	—	—	—	(4.4)	(4.3)	(4.3)
Amortization of Net Actuarial Loss	4.7	2.9	4.4	0.3	1.2	0.5
Net Periodic Benefit Cost (Credit)	6.0	3.7	5.2	(6.5)	(5.0)	(6.2)
Capitalized Portion	(2.8)	(2.4)	(2.6)	(0.3)	(0.2)	(0.3)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.2	$ 1.3	$ 2.6	$ (6.8)	$ (5.2)	$ (6.5)

SWEPCo	Pension Plans			OPEB		
	Years Ended December 31,					
	2020	2019	2018	2020	2019	2018
	(in millions)					
Service Cost	$ 9.9	$ 8.6	$ 9.3	$ 0.8	$ 0.8	$ 0.9
Interest Cost	10.2	12.4	11.3	2.5	3.1	2.8
Expected Return on Plan Assets	(15.7)	(17.7)	(17.3)	(6.3)	(5.9)	(6.4)
Amortization of Prior Service Credit	—	—	—	(5.2)	(5.2)	(5.2)
Amortization of Net Actuarial Loss	5.7	3.4	5.1	0.4	1.4	0.6
Settlements	—	—	0.4	—	—	—
Net Periodic Benefit Cost (Credit)	10.1	6.7	8.8	(7.8)	(5.8)	(7.3)
Capitalized Portion	(3.4)	(2.9)	(3.1)	(0.3)	(0.3)	(0.3)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 6.7	$ 3.8	$ 5.7	$ (8.1)	$ (6.1)	$ (7.6)

American Electric Power System Retirement Savings Plan

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

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

Company	Year Ended December 31, 2020	2019	2018
		(in millions)	
AEP	$ 81.8	$ 76.4	$ 71.8
AEP Texas	6.4	5.9	5.7
APCo	7.7	7.5	7.5
I&M	11.3	11.0	10.5
OPCo	7.3	6.6	6.3
PSO	4.9	4.6	4.5
SWEPCo	6.7	6.2	5.9

UMWA Benefits

Health and Welfare Benefits (Applies to AEP and APCo)

AEP provides health and welfare benefits negotiated with the UMWA for certain unionized employees, retirees and their survivors who meet eligibility requirements. APCo also provides the same UMWA health and welfare benefits for certain unionized mining retirees and their survivors who meet eligibility requirements. AEP and APCo administer the health and welfare benefits and pay them from their general assets.

Multiemployer Pension Benefits (Applies to AEP)

UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), a multiemployer plan. The UMWA pension benefits are administered by a board of trustees appointed in equal numbers by the UMWA and the Bituminous Coal Operators' Association (BCOA), an industry bargaining association. AEP makes contributions to the United Mine Workers of America 1974 Pension Plan based on provisions in its labor agreement and the plan documents. The UMWA pension plan is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. A withdrawing employer may be subject to a withdrawal liability, which is calculated based upon that employer's share of the plan's unfunded benefit obligations. If an employer fails to make required contributions or if its payments in connection with its withdrawal liability fall short of satisfying its share of the plan's unfunded benefit obligations, the remaining employers may be allocated a greater share of the remaining unfunded plan obligations. Under the Pension Protection Act of 2006 (PPA), the UMWA pension plan was in Critical and Declining Status for the plan years ending June 30, 2020 and 2019, without utilization of extended amortization provisions. As required under the PPA, the Plan adopted a Rehabilitation Plan in 2015. The Rehabilitation Plan has been updated annually, most recently in April 2020.

The amounts contributed by AEP affiliates in 2020, 2019 and 2018 were immaterial and represent less than 5% of the total contributions in the plan's latest annual report based on the plan year ended June 30, 2019. The contributions in 2020, 2019 and 2018 did not include surcharges.

Under the terms of the UMWA pension plan, contributions will be required to continue beyond the December 31, 2020 expiration of the current collective bargaining agreement between the Cook Coal Terminal (CCT) facility and the UMWA, whether or not the term of that agreement is extended or a subsequent agreement is entered, so long as both the UMWA pension plan remains in effect and an AEP affiliate continues to operate the facility covered by the current collective bargaining agreement. The contribution rate applicable would be determined in accordance with the terms of the UMWA pension plan by reference to the National Bituminous Coal Wage Agreement, subject to periodic revisions, between the UMWA and the BCOA. If the UMWA pension plan would terminate or an AEP affiliate would cease operation of the facility without arranging for a successor operator to assume its liability, the withdrawal liability obligation would be triggered.

Based upon the planned closure of CCT in 2022, AEP records a UMWA pension withdrawal liability on the balance sheet. The UMWA pension withdrawal liability is re-measured annually and is the estimated value of the company's anticipated contributions toward its proportionate share of the plan's unfunded vested liabilities. As of December 31, 2020 and 2019, the liability balance was $25 million and $20 million, respectively. AEP recovers the estimated value of its UMWA pension withdrawal liability through fuel clauses in certain regulated jurisdictions. AEP records a regulatory asset on the balance sheets when the UMWA pension withdrawal liability exceeds the cumulative billings collected and a regulatory liability on the balance sheets when the cumulative billings collected exceed the withdrawal liability. As of December 31, 2020 and 2019, AEP recorded a regulatory asset on the balance sheets for $6 million and $2 million, respectively. If any portion of the UMWA pension withdrawal liability is not recoverable, it could reduce future net income and cash flows and impact financial condition.

9. BUSINESS SEGMENTS

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

AEP's Reportable Segments

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by 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 returns on equity.
- Development, construction and operation of transmission facilities through investments in AEP's transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

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

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, income tax expense and other nonallocated costs.

The tables below present AEP's reportable segment income statement information for the years ended December 31, 2020, 2019 and 2018 and reportable segment balance sheet information as of December 31, 2020 and 2019.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)		Reconciling Adjustments		Consolidated
				(in millions)					
2020									
Revenues from:									
External Customers	$ 8,753.2	$ 4,238.7	$ 297.4	$ 1,621.0	$ 8.2		$ —		$ 14,918.5
Other Operating Segments	126.2	107.2	901.4	104.6	88.6		(1,328.0)		—
Total Revenues	$ 8,879.4	$ 4,345.9	$ 1,198.8	$ 1,725.6	$ 96.8		$ (1,328.0)		$ 14,918.5
Depreciation and Amortization	$ 1,600.5	$ 751.1	$ 257.6	$ 72.8	$ 0.8		$ —		$ 2,682.8
Interest Expense	565.0	289.2	133.2	24.0	196.4		(42.1)		1,165.7
Income Tax Expense (Benefit)	(7.0)	29.7	130.8	(108.0)	(5.0)		—		40.5
Equity Earnings of Unconsolidated Subsidiaries	2.9	—	82.4	3.2	2.6		—		91.1
Net Income (Loss)	$ 1,064.5	$ 496.4	$ 508.5	$ 216.9	$ (89.6)		$ —		$ 2,196.7
Gross Property Additions	$ 2,291.2	$ 2,108.1	$ 1,649.3	$ 197.0	$ 16.0		$ (15.3)		$ 6,246.3
Total Property, Plant and Equipment	$ 49,023.3	$ 21,145.0	$ 11,827.2	$ 1,910.2	$ 407.3		$ —		$ 84,313.0
Accumulated Depreciation and Amortization	15,586.2	3,879.3	595.7	166.1	184.1		—		20,411.4
Total Property, Plant and Equipment – Net	$ 33,437.1	$ 17,265.7	$ 11,231.5	$ 1,744.1	$ 223.2		$ —		$ 63,901.6
Total Assets	$ 42,752.7	$ 19,765.9	$ 12,627.3	$ 3,585.9	$ 5,987.1	(b)	$ (3,961.7)	(c)	$ 80,757.2
Investments in Equity Method Investees	$ 37.1	$ 2.1	$ 831.3	$ 467.0	$ 68.8		$ —		$ 1,406.3
Long-term Debt Due Within One Year:									
Nonaffiliated	$ 1,034.6	$ 588.8	$ 52.3	$ —	$ 410.4	(d)	$ —		$ 2,086.1
Long-term Debt:									
Affiliated	65.0	—	—	—	—		(65.0)		—
Nonaffiliated	12,375.6	6,661.9	4,075.7	—	5,873.2	(d)	—		28,986.4
Total Long-term Debt	$ 13,475.2	$ 7,250.7	$ 4,128.0	$ —	$ 6,283.6		$ (65.0)		$ 31,072.5

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	$ 9,245.7	$ 4,319.0	$ 260.2	$ 1,721.8	$ 14.7	$ —	$ 15,561.4
Other Operating Segments	121.4	163.5	813.0	135.8	81.1	(1,314.8)	—
Total Revenues	$ 9,367.1	$ 4,482.5	$ 1,073.2	$ 1,857.6	$ 95.8	$ (1,314.8)	$ 15,561.4
Asset Impairments and Other Related Charges	$ 92.9	$ 32.5	$ —	$ 31.0	$ —	$ —	$ 156.4
Depreciation and Amortization	1,447.0	789.5	183.4	69.5	0.6	24.5 (e)	2,514.5
Interest Expense	568.3	243.3	103.3	30.0	193.7	(66.1) (e)	1,072.5
Income Tax Expense (Benefit)	(97.7)	(25.2)	136.2	(53.8)	27.6	—	(12.9)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	3.0	—	72.8	(3.8)	0.1	—	72.1
Net Income (Loss)	$ 985.6	$ 451.0	$ 520.1	$ 104.1	$ (141.0)	$ —	$ 1,919.8
Gross Property Additions	$ 2,437.4	$ 2,074.3	$ 1,458.9	$ 1,005.1	$ 14.5	$ (20.4)	$ 6,969.8
Total Property, Plant and Equipment	$ 47,323.7	$ 19,773.3	$ 10,334.0	$ 1,650.8	$ 418.4	$ (354.5) (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
Investments in Equity Method Investees	$ 41.7	$ 2.5	$ 787.5	$ 459.5	$ 65.4	$ —	$ 1,356.6
Long-term Debt Due Within One Year:							
Affiliated	$ 20.0	$ —	$ —	$ —	$ —	$ (20.0)	—
Nonaffiliated	704.7	392.2	—	—	501.8 (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	—	25,126.8
Total Long-term Debt	$ 12,925.7	$ 6,640.3	$ 3,593.8	$ —	$ 3,624.7 (d)	$ (59.0)	$ 26,725.5

2018	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other(a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 9,556.7	$ 4,552.3	$ 248.6	$ 1,818.1	$ 20.0	$ —	$ 16,195.7
Other Operating Segments	88.8	100.8	555.5	122.2	75.1	(942.4)	—
Total Revenues	$ 9,645.5	$ 4,653.1	$ 804.1	$ 1,940.3	$ 95.1	$ (942.4)	$ 16,195.7
Asset Impairments and Other Related Charges	$ 3.4	$ —	$ —	$ 47.7	$ 19.5	$ —	$ 70.6
Depreciation and Amortization	1,316.2	734.1	137.8	41.0	0.4	57.1 (e)	2,286.6
Interest Expense	567.8	248.1	90.7	14.9	122.6	(59.7) (e)	984.4
Income Tax Expense	5.7	42.4	95.3	(49.2)	21.1	—	115.3
Equity Earnings of Unconsolidated Subsidiaries	2.7	—	68.7	0.5	1.2	—	73.1
Net Income (Loss)	$ 995.5	$ 527.4	$ 373.0	$ 134.7	$ (99.3)	$ —	$ 1,931.3
Gross Property Additions	$ 2,282.2	$ 2,162.4	$ 1,614.1	$ 289.7	$ 16.3	$ (39.2)	$ 6,325.5
Total Assets	$ 38,874.3	$ 17,083.4	$ 9,543.7	$ 1,979.7	$ 4,036.5 (b)	$ (2,714.8) (c)(e)	$ 68,802.8

(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 reflect 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 seven State Transcos operating segments all have similar economic characteristics and meet all of the criteria under the accounting guidance for "Segment Reporting" to be aggregated into one operating segment. As a result, AEPTCo has one reportable segment. The remainder of AEPTCo's activity is presented in AEPTCo Parent. While not considered a reportable segment, AEPTCo Parent represents the activity of the holding company which primarily relates to debt financing activity and general corporate activities.

The tables below present AEPTCo's reportable segment income statement information for the years ended December 31, 2020, 2019 and 2018 and reportable segment balance sheet information as of December 31, 2020 and 2019.

2020	State Transcos	AEPTCo Parent	Reconciling Adjustments		AEPTCo Consolidated
		(in millions)			
Revenues from:					
External Customers	$ 248.8	$ —	$ —		$ 248.8
Sales to AEP Affiliates	896.3	—	—		896.3
Other Revenues	0.6	—	—		0.6
Total Revenues	$ 1,145.7	$ —	$ —		$ 1,145.7
Depreciation and Amortization	$ 249.0	$ —	$ —		$ 249.0
Interest Income	0.9	149.6	(148.1)	(a)	2.4
Allowance for Equity Funds Used During Construction	74.0	—	—		74.0
Interest Expense	127.8	148.1	(148.1)	(a)	127.8
Income Tax Expense	106.5	0.2	—		106.7
Net Income	$ 422.3	$ 1.1 (b)	$ —		$ 423.4
Gross Property Additions	$ 1,621.9	$ —	$ —		$ 1,621.9
Total Transmission Property	$ 11,345.6	$ —	$ —		$ 11,345.6
Accumulated Depreciation and Amortization	572.8	—	—		572.8
Total Transmission Property - Net	$ 10,772.8	$ —	$ —		$ 10,772.8
Notes Receivable - Affiliated	$ —	$ 3,948.5	$ (3,948.5)	(c)	$ —
Total Assets	$ 11,185.1	$ 4,084.0 (d)	$ (4,023.1)	(e)	$ 11,246.0
Total Long-Term Debt	$ 3,990.0	$ 3,948.5	$ (3,990.0)	(c)	$ 3,948.5

2019	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
		(in millions)				
Revenues from:						
External Customers	$ 214.6	$ —		$ —		$ 214.6
Sales to AEP Affiliates	806.7	—		—		806.7
Other Revenues	0.1	—		—		0.1
Total Revenues	$ 1,021.4	$ —		$ —		$ 1,021.4
Depreciation and Amortization	$ 176.0	$ —		$ —		$ 176.0
Interest Income	1.3	123.8		(122.1)	(a)	3.0
Allowance for Equity Funds Used During Construction	84.3	—		—		84.3
Interest Expense	97.4	122.1		(122.1)	(a)	97.4
Income Tax Expense	117.1	0.3		—		117.4
Net Income	$ 438.6	$ 1.1	(b)	$ —		$ 439.7
Gross Property Additions	$ 1,419.5	$ —		$ —		$ 1,419.5
Total Transmission Property	$ 9,893.2	$ —		$ —		$ 9,893.2
Accumulated Depreciation and Amortization	402.3	—		—		402.3
Total Transmission Property - Net	$ 9,490.9	$ —		$ —		$ 9,490.9
Notes Receivable - Affiliated	$ —	$ 3,427.3		$ (3,427.3)	(c)	$ —
Total Assets	$ 9,865.0	$ 3,519.1	(d)	$ (3,493.3)	(e)	$ 9,890.8
Total Long-Term Debt	$ 3,465.0	$ 3,427.3		$ (3,465.0)	(c)	$ 3,427.3

2018	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
		(in millions)				
Revenues from:						
External Customers	$ 177.0	$ —		$ —		$ 177.0
Sales to AEP Affiliates	598.9	—		—		598.9
Other	0.2	—		—		0.2
Total Revenues	$ 776.1	$ —		$ —		$ 776.1
Depreciation and Amortization	$ 133.9	$ —		$ —		$ 133.9
Interest Income	1.3	104.6		(103.4)	(a)	2.5
Allowance for Equity Funds Used During Construction	70.6	—		—		70.6
Interest Expense	83.2	103.4		(103.4)	(a)	83.2
Income Tax Expense	83.9	0.2		—		84.1
Net Income	$ 314.9	$ 1.0	(b)	$ —		$ 315.9
Gross Property Additions	$ 1,570.8	$ —		$ —		$ 1,570.8
Total Assets	$ 8,406.8	$ 2,857.1	(d)	$ (2,869.8)	(e)	$ 8,394.1

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

10. 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 Subsidiaries. AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

The Registrants utilize power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. The Registrants utilize interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. The Registrants also utilize derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors.

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

Primary Risk Exposure	Unit of Measure	December 31, 2020						
		AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	331.3	—	46.9	19.7	3.0	11.9	4.0
Natural Gas	MMBtus	26.9	—	—	—	—	—	7.9
Heating Oil and Gasoline	Gallons	6.9	1.8	1.1	0.6	1.4	0.7	0.9
Interest Rate	USD	$ 129.8	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 1,150.0	$ —	$ 200.0	$ —	$ —	$ —	$ —

Primary Risk Exposure	Unit of Measure	December 31, 2019						
		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 and other 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 $3 million and $5 million as of December 31, 2020 and 2019, respectively. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $7 million and $39 million as of December 31, 2020 and 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 December 31, 2020 and 2019.

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

AEP

	December 31, 2020					
	Risk Management Contracts	Hedging Contracts		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)
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**			
			(in millions)			
Current Risk Management Assets	$ 239.1	$ 21.1	$ 5.0	$ 265.2	$ (170.5)	$ 94.7
Long-term Risk Management Assets	275.9	18.0	—	293.9	(51.7)	242.2
Total Assets	515.0	39.1	5.0	559.1	(222.2)	336.9
Current Risk Management Liabilities	193.0	54.4	3.4	250.8	(172.0)	78.8
Long-term Risk Management Liabilities	222.2	60.1	4.1	286.4	(53.6)	232.8
Total Liabilities	415.2	114.5	7.5	537.2	(225.6)	311.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 99.8	$ (75.4)	$ (2.5)	$ 21.9	$ 3.4	$ 25.3

	December 31, 2019					
	Risk Management Contracts	Hedging Contracts		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)
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**			
			(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

Balance Sheet Location	December 31, 2020 Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.4	$ (0.4)	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	0.4	(0.4)	—
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Net Assets (Liabilities)	$ 0.4	$ (0.4)	$ —

Balance Sheet Location	December 31, 2019 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

Balance Sheet Location	December 31, 2020 Risk Management 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	$ 38.8	$ 2.4	$ 41.2	$ (18.8)	$ 22.4
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.7	—	0.7	(0.6)	0.1
Total Assets	39.5	2.4	41.9	(19.4)	22.5
Current Risk Management Liabilities	19.7	3.4	23.1	(18.5)	4.6
Deferred Credits and Other Noncurrent Liabilities - Long-term Risk Management Liabilities	0.6	—	0.6	(0.5)	0.1
Total Liabilities	20.3	3.4	23.7	(19.0)	4.7
Total MTM Derivative Contract Net Assets (Liabilities)	$ 19.2	$ (1.0)	$ 18.2	$ (0.4)	$ 17.8

Balance Sheet Location	December 31, 2019 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
Deferred Charges and Other Noncurrent Assets - 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
Deferred Credits and Other Noncurrent Liabilities - 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

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)
	December 31, 2020		
		(in millions)	
Current Risk Management Assets	$ 17.2	$ (13.6)	$ 3.6
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.5	(0.4)	0.1
Total Assets	17.7	(14.0)	3.7
Other Current Liabilities - Current Risk Management Liabilities	12.1	(12.0)	0.1
Deferred Credits and Other Noncurrent Liabilities - Long-term Risk Management Liabilities	0.4	(0.3)	0.1
Total Liabilities	12.5	(12.3)	0.2
Total MTM Derivative Contract Net Assets (Liabilities)	$ 5.2	$ (1.7)	$ 3.5

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)
	December 31, 2019		
		(in millions)	
Current Risk Management Assets	$ 66.9	$ (57.1)	$ 9.8
Deferred Charges and Other Noncurrent Assets - Long-term Risk Management Assets	0.5	(0.4)	0.1
Total Assets	67.4	(57.5)	9.9
Other Current Liabilities - Current Risk Management Liabilities	55.2	(54.7)	0.5
Deferred Credits and Other Noncurrent Liabilities - 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

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)
	December 31, 2020		
		(in millions)	
Current Risk Management Assets	$ 0.3	$ (0.3)	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	0.3	(0.3)	—
Current Risk Management Liabilities	8.7	—	8.7
Long-term Risk Management Liabilities	101.6	—	101.6
Total Liabilities	110.3	—	110.3
Total MTM Derivative Contract Net Liabilities	$ (110.0)	$ (0.3)	$ (110.3)

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)
	December 31, 2019		
		(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

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)
	December 31, 2020		
		(in millions)	
Current Risk Management Assets	$ 10.5	$ (0.2)	$ 10.3
Long-term Risk Management Assets	—	—	—
Total Assets	10.5	(0.2)	10.3
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Net Assets (Liabilities)	$ 10.5	$ (0.2)	$ 10.3

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)
	December 31, 2019		
		(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

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)
	December 31, 2020		
		(in millions)	
Current Risk Management Assets	$ 3.4	$ (0.2)	$ 3.2
Long-term Risk Management Assets	—	—	—
Total Assets	3.4	(0.2)	3.2
Current Risk Management Liabilities	0.7	—	0.7
Long-term Risk Management Liabilities	1.0	—	1.0
Total Liabilities	1.7	—	1.7
Total MTM Derivative Net Assets (Liabilities)	$ 1.7	$ (0.2)	$ 1.5

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)
	December 31, 2019		
		(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' amount of gain (loss) recognized on risk management contracts:

	Year Ended December 31, 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	9.5	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.4	0.1	—	—	0.1
Purchased Electricity for Resale	1.4	—	1.2	0.1	—	—	—
Other Operation	(2.0)	(0.6)	(0.2)	(0.2)	(0.3)	(0.2)	(0.3)
Maintenance	(2.9)	(0.8)	(0.4)	(0.3)	(0.5)	(0.3)	(0.4)
Regulatory Assets (a)	(4.8)	—	—	(0.1)	(6.6)	—	1.4
Regulatory Liabilities (a)	114.9	0.4	20.3	12.4	12.4	39.1	20.2
Total Gain (Loss) on Risk Management Contracts	$ 116.9	$ (1.0)	$ 21.3	$ 12.0	$ 5.0	$ 38.6	$ 21.0

	Year Ended December 31, 2019						
Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 0.7	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	25.1	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	0.5	—	—	0.1
Purchased Electricity for Resale	1.9	—	1.6	0.1	—	—	—
Other Operation	(0.8)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)
Maintenance	(0.8)	(0.2)	(0.2)	(0.1)	(0.2)	(0.1)	(0.1)
Regulatory Assets (a)	(3.7)	0.7	0.3	0.3	(3.7)	1.2	(1.5)
Regulatory Liabilities (a)	102.6	—	2.4	24.5	10.1	34.6	26.6
Total Gain on Risk Management Contracts	$ 125.0	$ 0.3	$ 4.1	$ 25.2	$ 6.0	$ 35.6	$ 25.0

	Year Ended December 31, 2018						
Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ (10.4)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	38.9	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(1.9)	(8.2)	—	—	0.1
Purchased Electricity for Resale	8.6	—	7.6	0.8	—	—	—
Other Operation	1.7	0.4	0.2	0.2	0.3	0.2	0.2
Maintenance	1.9	0.4	0.4	0.2	0.4	0.2	0.2
Regulatory Assets (a)	27.9	(0.7)	(0.7)	7.1	24.9	(1.1)	(1.2)
Regulatory Liabilities (a)	222.7	(0.5)	135.5	11.6	—	37.3	11.9
Total Gain (Loss) on Risk Management Contracts	$ 291.3	$ (0.4)	$ 141.1	$ 11.7	$ 25.6	$ 36.6	$ 11.2

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

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the statements of income as that of the associated risk. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies (Applies to AEP)

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts net income during the period of change.

AEP records realized and unrealized gains or losses on interest rate swaps that are designated and qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income.

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

	Carrying Amount of the Hedged Assets/(Liabilities)		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Assets/(Liabilities)	
	December 31, 2020	**December 31, 2019**	**December 31, 2020**	**December 31, 2019**
		(in millions)		
Long-term Debt (a) (b)	$ (995.9)	$ (510.8)	$ (51.7)	$ (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 $(53) million and $0 as of December 31, 2020 and 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:

	Years Ended December 31,		
	2020	**2019**	**2018**
		(in millions)	
Gain (Loss) on Interest Rate Contracts:			
Fair Value Hedging Instruments (a)	$ 41.1	$ 31.9	$ (11.3)
Fair Value Portion of Long-term Debt (a)	(41.1)	(31.9)	11.3

(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 years ended 2020, 2019 and 2018, AEP applied cash flow hedging to outstanding power derivatives. During the years ended 2020, 2019 and 2018, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the years ended 2020, 2019 and 2018, AEP applied cash flow hedging to outstanding interest rate derivatives. During the year ended 2020, APCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the year ended 2019, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives. During the year ended 2018, SWEPCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

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

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

Impact of Cash Flow Hedges on AEP's Balance Sheets

	December 31, 2020		December 31, 2019	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ (60.6)	$ (47.5)	$ (103.5)	$ (11.5)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	(27.1)	(5.7)	(51.7)	(2.1)

As of December 31, 2020 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 123 months and 120 months for commodity and interest rate hedges, respectively.

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

	December 31, 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	$ (2.3)	$ (1.1)	$ (3.4)	$ (1.1)
APCo	(0.8)	0.4	0.9	0.9
I&M	(8.3)	(1.6)	(9.9)	(1.6)
PSO	0.1	0.1	1.1	1.0
SWEPCo	(0.3)	(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, surety bonds and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Collateral Triggering Events

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

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

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

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

	December 31, 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	$ 188.4	$ —	$ 169.2
APCo	4.3	—	3.5
I&M	0.5	—	0.1
SWEPCo	1.8	—	1.8

	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

Warrants Held in Investee (Applies to AEP)

As of December 31, 2020, AEP held an $8 million investment in a privately held investee that is anticipated to complete an initial public offering (IPO) in the first quarter of 2021**.** The IPO is expected to be completed via a reverse merger with a public special purpose acquisition company. AEP's interests in the investee as of December 31, 2020 consisted of a noncontrolling equity interest of preferred shares, which were accounted for at historical cost until completion of the IPO, and common share warrants, which management has determined are derivative instruments based on the accounting guidance for "Derivatives and Hedging".

As of December 31, 2020, the warrants were valued at $32 million and were recorded in Deferred Charges and Other Noncurrent Assets on AEP's balance sheet. AEP recognized an unrealized gain of $32 million associated with the warrants for the year ended December 31, 2020, presented in Other Income on AEP's statement of income.

Management utilized a Black-Scholes options pricing model to value the warrants as of December 31, 2020. As the reverse merger and IPO did not close prior to the end of 2020, the valuation contemplated a liquidity adjustment that resulted in the overall fair value of the warrants being categorized as Level 3 in the fair value hierarchy. See "Fair Value Measurements of Financial Assets and Liabilities" section of Note 11 for additional information.

11. FAIR VALUE MEASUREMENTS

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

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

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

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

	December 31,			
	2020		2019	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in millions)			
AEP (a)	$ 31,072.5	$ 37,457.0	$ 26,725.5	$ 30,172.0
AEP Texas	4,820.4	5,682.6	4,558.4	4,981.5
AEPTCo	3,948.5	4,984.3	3,427.3	3,868.0
APCo	4,834.1	6,391.8	4,363.8	5,253.1
I&M	3,029.9	3,775.3	3,050.2	3,453.8
OPCo	2,430.2	3,154.9	2,082.0	2,554.3
PSO	1,373.8	1,732.1	1,386.2	1,603.3
SWEPCo	2,636.4	3,210.1	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 $1.7 billion and $871 million as of December 31, 2020 and 2019, respectively. See "Equity Units" section of Note 14 for additional information.

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS. See "Other Temporary Investments" section of Note 1 for additional information.

The following is a summary of Other Temporary Investments:

	December 31, 2020			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$ 68.3	$ —	$ —	$ 68.3
Fixed Income Securities – Mutual Funds (b)	120.7	2.8	—	123.5
Equity Securities – Mutual Funds	25.9	28.7	—	54.6
Total Other Temporary Investments	$ 214.9	$ 31.5	$ —	$ 246.4

Other Temporary Investments	December 31, 2019 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:

	Years Ended December 31, 2020	2019	2018
		(in millions)	
Proceeds from Investment Sales	$ 50.9	$ 21.2	$ —
Purchases of Investments	41.6	45.0	3.1
Gross Realized Gains on Investment Sales	3.8	—	—
Gross Realized Losses on Investment Sales	0.2	0.4	—

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal (Applies to AEP and I&M)

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1 for additional information.

The following is a summary of nuclear trust fund investments:

	December 31, 2020 Fair Value	2020 Gross Unrealized Gains	2020 Other-Than-Temporary Impairments	2019 Fair Value	2019 Gross Unrealized Gains	2019 Other-Than-Temporary Impairments
			(in millions)			
Cash and Cash Equivalents	$ 25.8	$ —	$ —	$ 15.3	$ —	$ —
Fixed Income Securities:						
United States Government	1,025.6	98.5	(7.1)	1,112.5	55.5	(6.1)
Corporate Debt	86.3	9.6	(1.7)	72.4	5.3	(1.6)
State and Local Government	114.3	0.9	(0.4)	7.6	0.7	(0.2)
Subtotal Fixed Income Securities	1,226.2	109.0	(9.2)	1,192.5	61.5	(7.9)
Equity Securities - Domestic (a)	2,054.7	1,400.8	—	1,767.9	1,144.4	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 3,306.7	$ 1,509.8	$ (9.2)	$ 2,975.7	$ 1,205.9	$ (7.9)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $1.4 billion and $1.1 billion and unrealized losses of $9 million and $5 million as of December 31, 2020 and 2019, respectively.

The following table provides the securities activity within the decommissioning and SNF trusts:

	Years Ended December 31, 2020	2019	2018
		(in millions)	
Proceeds from Investment Sales	$ 1,593.4	$ 1,473.0	$ 2,010.0
Purchases of Investments	1,637.2	1,531.0	2,064.7
Gross Realized Gains on Investment Sales	26.4	76.5	47.5
Gross Realized Losses on Investment Sales	26.1	24.3	32.8

The base cost of fixed income securities was $1.1 billion and $1.1 billion as of December 31, 2020 and 2019, respectively. The base cost of equity securities was $654 million and $623 million as of December 31, 2020 and 2019, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2020 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 294.8
After 1 year through 5 years	371.3
After 5 years through 10 years	214.4
After 10 years	345.7
Total	$ 1,226.2

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

	December 31, 2020				
	Level 1	**Level 2**	**Level 3**	**Other**	**Total**
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 57.8	$ —	$ —	$ 10.5	$ 68.3
Fixed Income Securities – Mutual Funds	123.5	—	—	—	123.5
Equity Securities – Mutual Funds (b)	54.6	—	—	—	54.6
Total Other Temporary Investments	235.9	—	—	10.5	246.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	0.9	258.8	252.4	(190.0)	322.1
Cash Flow Hedges:					
Commodity Hedges (c)	—	34.4	3.9	(28.5)	9.8
Interest Rate Hedges	—	2.4	—	—	2.4
Fair Value Hedges	—	2.6	—	—	2.6
Total Risk Management Assets	0.9	298.2	256.3	(218.5)	336.9
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	16.8	—	—	9.0	25.8
Fixed Income Securities:					
United States Government	—	1,025.6	—	—	1,025.6
Corporate Debt	—	86.3	—	—	86.3
State and Local Government	—	114.3	—	—	114.3
Subtotal Fixed Income Securities	—	1,226.2	—	—	1,226.2
Equity Securities – Domestic (b)	2,054.7	—	—	—	2,054.7
Total Spent Nuclear Fuel and Decommissioning Trusts	2,071.5	1,226.2	—	9.0	3,306.7
Other Investments (h)	—	—	31.8	—	31.8
Total Assets	$ 2,308.3	$ 1,524.4	$ 288.1	$ (199.0)	$ 3,921.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 0.9	$ 244.2	$ 167.2	$ (193.4)	$ 218.9
Cash Flow Hedges:					
Commodity Hedges (c)	—	106.1	7.6	(28.5)	85.2
Interest Rate Hedges	—	3.4	—	—	3.4
Fair Value Hedges	—	4.1	—	—	4.1
Total Risk Management Liabilities	$ 0.9	$ 357.8	$ 174.8	$ (221.9)	$ 311.6

AEP

Assets:	December 31, 2019 Level 1	Level 2	Level 3 (in millions)	Other	Total
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:	December 31, 2020 Level 1	Level 2	Level 3 (in millions)	Other	Total
Restricted Cash for Securitized Funding	$ 28.7	$ —	$ —	$ —	$ 28.7
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.4	—	(0.4)	—
Total Assets	$ 28.7	$ 0.4	$ —	$ (0.4)	$ 28.7

Assets:	December 31, 2019 Level 1	Level 2	Level 3 (in millions)	Other	Total
Restricted Cash for Securitized Funding	$ 154.7	$ —	$ —	$ —	$ 154.7

APCo

Assets:	December 31, 2020 Level 1	Level 2	Level 3 (in millions)	Other	Total
Restricted Cash for Securitized Funding	$ 16.9	$ —	$ —	$ —	$ 16.9
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	19.4	19.9	(19.2)	20.1
Cash Flow Hedges:					
Interest Rate Hedges	—	2.4	—	—	2.4
Total Risk Management Assets	—	21.8	19.9	(19.2)	22.5
Total Assets	$ 16.9	$ 21.8	$ 19.9	$ (19.2)	$ 39.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 19.5	$ 0.6	$ (18.8)	$ 1.3
Cash Flow Hedges:					
Interest Rate Hedges	—	3.4	—	—	3.4
Total Risk Management Liabilities	$ —	$ 22.9	$ 0.6	$ (18.8)	$ 4.7

Assets:	December 31, 2019 Level 1	Level 2	Level 3 (in millions)	Other	Total
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

	December 31, 2020				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 15.1	$ 2.5	$ (13.9)	$ 3.7
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	16.8	—	—	9.0	25.8
Fixed Income Securities:					
United States Government	—	1,025.6	—	—	1,025.6
Corporate Debt	—	86.3	—	—	86.3
State and Local Government	—	114.3	—	—	114.3
Subtotal Fixed Income Securities	—	1,226.2	—	—	1,226.2
Equity Securities - Domestic (b)	2,054.7	—	—	—	2,054.7
Total Spent Nuclear Fuel and Decommissioning Trusts	2,071.5	1,226.2	—	9.0	3,306.7
Total Assets	$ 2,071.5	$ 1,241.3	$ 2.5	$ (4.9)	$ 3,310.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 12.0	$ 0.4	$ (12.2)	$ 0.2

	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

	December 31, 2020				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ —	$ (0.3)	$ —
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 110.3	$ —	$ 110.3

	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

	December 31, 2020				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 10.3	$ (0.2)	$ 10.3

	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:	December 31, 2020 Level 1	Level 2	Level 3 (in millions)	Other	Total
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.1	$ 3.3	$ (0.2)	$ 3.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 1.7	$ —	$ 1.7

Assets:	December 31, 2019 Level 1	Level 2	Level 3 (in millions)	Other	Total
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 December 31, 2020 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 2 matures $3 million in periods 2022-2024, $11 million in periods 2025-2026 and $1 million in periods 2027-2033; Level 3 matures $47 million in 2021, $37 million in periods 2022-2024, $14 million in periods 2025-2026 and $(13) million in periods 2027-2033. 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 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were 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.
(h) See "Warrants Held in Investee" section of Note 10 for additional information.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 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)	39.5	13.2	2.5	(1.6)	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)	35.3	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	13.8	—	—	—	—	—
Settlements	(113.1)	(51.6)	(8.6)	8.9	(27.6)	(6.6)
Transfers into Level 3 (d) (e)	(3.8)	—	—	—	—	—
Transfers out of Level 3 (e)	5.6	0.7	0.4	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	26.1	19.3	2.0	(14.0)	10.2	4.0
Balance as of December 31, 2020	$ 113.3	$ 19.3	$ 2.1	$ (110.3)	$ 10.3	$ 1.6

Year Ended December 31, 2019	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2018	$ 131.2	$ 57.8	$ 8.9	$ (99.4)	$ 9.5	$ 2.3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	15.8	(13.9)	4.7	(0.9)	13.5	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(0.1)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(15.1)	—	—	—	—	—
Settlements	(117.6)	(42.5)	(13.0)	6.6	(23.0)	(9.6)
Transfers into Level 3 (d) (e)	(0.6)	(0.5)	(0.3)	—	—	—
Transfers out of Level 3 (e)	35.6	(0.7)	(0.4)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	60.7	37.5	5.9	(9.9)	15.8	2.7
Balance as of December 31, 2019	$ 109.9	$ 37.7	$ 5.8	$ (103.6)	$ 15.8	$ 1.4

Year Ended December 31, 2018	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2017	$ 40.3	$ 24.7	$ 7.6	$ (132.4)	$ 6.2	$ 5.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	148.9	104.1	14.2	1.8	18.1	(4.8)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	9.8	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	15.7	—	—	—	—	—
Settlements	(214.0)	(127.9)	(21.3)	4.6	(24.3)	(2.1)
Transfers into Level 3 (d) (e)	15.8	—	—	—	—	—
Transfers out of Level 3 (e)	(1.6)	—	(0.3)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	116.3	56.9	8.7	26.6	9.5	3.3
Balance as of December 31, 2018	$ 131.2	$ 57.8	$ 8.9	$ (99.4)	$ 9.5	$ 2.3

(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

December 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	**Liabilities**	**Technique**	**Input**	**Low**	**High**	**Weighted Average**
	(in millions)						
Energy Contracts	$ 213.5	$ 169.7	Discounted Cash Flow	Forward Market Price (a) (c)	$ 5.33	$100.47	$ 32.73
Natural Gas Contracts	—	1.7	Discounted Cash Flow	Forward Market Price (b) (c)	2.18	2.77	2.40
FTRs	42.8	3.4	Discounted Cash Flow	Forward Market Price (a) (c)	(15.08)	9.66	0.19
Other Investments	31.8	—	Black-Scholes Model	Liquidity Adjustment (d)	10 %	20 %	15 %
Total	$ 288.1	$ 174.8					

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

December 31, 2020							
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 1.0	$ 0.6	Discounted Cash Flow	Forward Market Price	$ 10.84	$ 41.09	$ 25.08
FTRs	18.9	—	Discounted Cash Flow	Forward Market Price	0.04	5.61	1.13
Total	$ 19.9	$ 0.6					

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

December 31, 2020							
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 0.6	$ 0.3	Discounted Cash Flow	Forward Market Price	$ 10.84	$ 41.09	$ 25.08
FTRs	1.9	0.1	Discounted Cash Flow	Forward Market Price	(1.96)	3.69	0.33
Total	$ 2.5	$ 0.4					

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

	December 31, 2020						
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 110.3	Discounted Cash Flow	Forward Market Price	$ 16.19	$ 46.98	$ 28.30

	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

	December 31, 2020						
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 10.3	$ —	Discounted Cash Flow	Forward Market Price	$ (6.93)	$ 0.48	$ (1.93)

	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

December 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ —	$ 1.7	Discounted Cash Flow	Forward Market Price (b)	$ 2.18	$ 2.77	$ 2.41
FTRs	3.3	—	Discounted Cash Flow	Forward Market Price (a)	(6.93)	0.48	(1.93)
Total	$ 3.3	$ 1.7					

December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ —	$ 4.9	Discounted Cash Flow	Forward Market Price (b)	$ 1.89	$ 2.51	$ 2.18
FTRs	6.5	0.2	Discounted Cash Flow	Forward Market Price (a)	(8.52)	0.85	(2.31)
Total	$ 6.5	$ 5.1					

(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.
(d) Represents percentage discount applied to the publically available share price.

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, FTRs and Other Investments for the Registrants as of December 31, 2020 and 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)
Liquidity Adjustment	Buy	Increase (Decrease)	Lower (Higher)

12. INCOME TAXES

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

Income Tax Expense (Benefit)

The details of the Registrants' Income Tax Expense (Benefit) as reported are as follows:

Year Ended December 31, 2020	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (138.2)	$ 5.2	$ 22.2	$ 21.4	$ 11.3	$ (26.6)	$ (11.4)	$ (13.6)
Deferred	146.9	(15.4)	65.4	(27.1)	(20.6)	74.0	8.3	19.6
Total Federal	8.7	(10.2)	87.6	(5.7)	(9.3)	47.4	(3.1)	6.0
State and Local:								
Current	(16.7)	(0.1)	2.8	9.3	1.9	(5.4)	0.1	(8.2)
Deferred	48.5	(0.9)	16.3	0.7	(0.1)	3.2	8.2	11.6
Total State and Local	31.8	(1.0)	19.1	10.0	1.8	(2.2)	8.3	3.4
Income Tax Expense (Benefit)	$ 40.5	$ (11.2)	$ 106.7	$ 4.3	$ (7.5)	$ 45.2	$ 5.2	$ 9.4

Year Ended December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (7.4)	$ (31.8)	$ 23.7	$ 36.7	$ 48.1	$ (10.0)	$ 25.5	$ 6.9
Deferred	(71.6)	(24.7)	71.7	(126.1)	(57.1)	40.6	(26.0)	(10.0)
Total Federal	(79.0)	(56.5)	95.4	(89.4)	(9.0)	30.6	(0.5)	(3.1)
State and Local:								
Current	4.4	2.9	2.4	12.0	(2.4)	1.1	0.2	0.8
Deferred	61.7	—	19.6	(0.6)	0.8	3.2	7.8	(2.4)
Total State and Local	66.1	2.9	22.0	11.4	(1.6)	4.3	8.0	(1.6)
Income Tax Expense (Benefit)	$ (12.9)	$ (53.6)	$ 117.4	$ (78.0)	$ (10.6)	$ 34.9	$ 7.5	$ (4.7)

Year Ended December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (31.7)	$ 37.0	$ (14.2)	$ (31.9)	$ 60.9	$ 55.6	$ 35.6	$ 18.3
Deferred	122.0	(17.9)	82.3	(24.5)	(48.8)	(36.9)	(36.7)	(1.9)
Total Federal	90.3	19.1	68.1	(56.4)	12.1	18.7	(1.1)	16.4
State and Local:								
Current	30.8	1.8	(0.6)	3.7	15.8	4.6	(0.2)	2.3
Deferred	(5.8)	(0.1)	16.6	7.8	1.2	0.7	6.3	1.7
Total State and Local	25.0	1.7	16.0	11.5	17.0	5.3	6.1	4.0
Income Tax Expense (Benefit)	$ 115.3	$ 20.8	$ 84.1	$ (44.9)	$ 29.1	$ 24.0	$ 5.0	$ 20.4

The following are reconciliations for the Registrants between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

AEP	Years Ended December 31, 2020	2019	2018
		(in millions)	
Net Income	$ 2,196.7	$ 1,919.8	$ 1,931.3
Less: Equity Earnings – Dolet Hills	(2.9)	(3.0)	(2.7)
Income Tax Expense (Benefit)	40.5	(12.9)	115.3
Pretax Income	$ 2,234.3	$ 1,903.9	$ 2,043.9
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 469.2	$ 399.8	$ 429.2
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	26.5	20.4	24.6
Investment Tax Credit Amortization	(18.8)	(13.0)	(20.4)
Production Tax Credits	(83.1)	(59.6)	(10.3)
State and Local Income Taxes, Net	25.1	52.2	19.7
Removal Costs	(18.6)	(22.2)	(18.6)
AFUDC	(32.5)	(37.1)	(29.4)
Tax Reform Adjustments	—	—	(10.9)
Tax Reform Excess ADIT Reversal	(268.2)	(353.2)	(257.2)
CARES Act	(48.0)	—	—
Other	(11.1)	(0.2)	(11.4)
Income Tax Expense (Benefit)	$ 40.5	$ (12.9)	$ 115.3
Effective Income Tax Rate	1.8 %	(0.7) %	5.6 %

AEP Texas	Years Ended December 31, 2020	2019	2018
		(in millions)	
Net Income	$ 241.0	$ 178.3	$ 211.3
Income Tax Expense (Benefit)	(11.2)	(53.6)	20.8
Pretax Income	$ 229.8	$ 124.7	$ 232.1
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 48.3	$ 26.2	$ 48.7
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.0	1.0	0.7
Investment Tax Credit Amortization	(1.1)	(1.2)	(2.3)
State and Local Income Taxes, Net	(0.8)	2.3	1.3
AFUDC	(4.1)	(3.2)	(4.2)
Parent Company Loss Benefit	(4.5)	(3.8)	(3.0)
Tax Reform Adjustments	—	—	(11.0)
Tax Reform Excess ADIT Reversal	(47.9)	(73.4)	(11.8)
Other	(2.1)	(1.5)	2.4
Income Tax Expense (Benefit)	$ (11.2)	$ (53.6)	$ 20.8
Effective Income Tax Rate	(4.9) %	(43.0) %	9.0 %

AEPTCo

	Years Ended December 31,		
	2020	2019	2018
		(in millions)	
Net Income	$ 423.4	$ 439.7	$ 315.9
Income Tax Expense	106.7	117.4	84.1
Pretax Income	$ 530.1	$ 557.1	$ 400.0
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 111.3	$ 117.0	$ 84.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
State and Local Income Taxes, Net	15.1	17.4	12.6
AFUDC	(15.5)	(17.7)	(14.1)
Parent Company Loss Benefit	(7.0)	(4.2)	(0.6)
Other	2.8	4.9	2.2
Income Tax Expense	$ 106.7	$ 117.4	$ 84.1
Effective Income Tax Rate	20.1 %	21.1 %	21.0 %

APCo

	Years Ended December 31,		
	2020	2019	2018
		(in millions)	
Net Income	$ 369.7	$ 306.3	$ 367.8
Income Tax Expense (Benefit)	4.3	(78.0)	(44.9)
Pretax Income	$ 374.0	$ 228.3	$ 322.9
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 78.5	$ 47.9	$ 67.8
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	12.7	10.8	9.4
State and Local Income Taxes, Net	7.9	9.0	9.1
Removal Costs	(5.7)	(6.4)	(7.9)
AFUDC	(4.5)	(5.2)	(4.3)
Parent Company Loss Benefit	(6.2)	(4.1)	(3.6)
Tax Reform Excess ADIT Reversal	(72.3)	(130.4)	(108.5)
Federal Return to Provision	(7.2)	(1.0)	(6.6)
Other	1.1	1.4	(0.3)
Income Tax Expense (Benefit)	$ 4.3	$ (78.0)	$ (44.9)
Effective Income Tax Rate	1.1 %	(34.2) %	(13.9) %

I&M

	Years Ended December 31,		
	2020	2019	2018
		(in millions)	
Net Income	$ 284.8	$ 269.4	$ 261.3
Income Tax Expense (Benefit)	(7.5)	(10.6)	29.1
Pretax Income	$ 277.3	$ 258.8	$ 290.4
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 58.2	$ 54.3	$ 61.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.6	4.0	1.5
Investment Tax Credit Amortization	(4.5)	(3.6)	(4.7)
State and Local Income Taxes, Net	1.5	(1.2)	13.4
Removal Costs	(10.5)	(12.8)	(8.0)
AFUDC	(2.4)	(4.1)	(2.5)
Parent Company Loss Benefit	(6.4)	(3.3)	(2.3)
Tax Reform Excess ADIT Reversal	(46.8)	(42.5)	(25.8)
Federal Return to Provision	1.9	(0.3)	(4.6)
Other	(0.1)	(1.1)	1.1
Income Tax Expense (Benefit)	$ (7.5)	$ (10.6)	$ 29.1
Effective Income Tax Rate	(2.7) %	(4.1) %	10.0 %

OPCo

	Years Ended December 31,		
	2020	2019	2018
		(in millions)	
Net Income	$ 271.4	$ 297.1	$ 325.5
Income Tax Expense	45.2	34.9	24.0
Pretax Income	$ 316.6	$ 332.0	$ 349.5
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 66.5	$ 69.7	$ 73.4
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	3.7	(1.4)	2.4
State and Local Income Taxes, Net	(1.7)	3.4	4.2
AFUDC	(2.6)	(3.8)	(2.1)
Parent Company Loss Benefit	—	(1.8)	(6.0)
Tax Reform Excess ADIT Reversal	(27.2)	(27.3)	(51.0)
Federal Return to Provision	6.5	(3.7)	0.2
Other	—	(0.2)	2.9
Income Tax Expense	$ 45.2	$ 34.9	$ 24.0
Effective Income Tax Rate	14.3 %	10.5 %	6.9 %

PSO

	Years Ended December 31,		
	2020	2019	2018
		(in millions)	
Net Income	$ 123.0	$ 137.6	$ 83.2
Income Tax Expense	5.2	7.5	5.0
Pretax Income	$ 128.2	$ 145.1	$ 88.2
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 26.9	$ 30.5	$ 18.5
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.1	0.6	0.7
Investment Tax Credit Amortization	(2.1)	(0.5)	(1.7)
State and Local Income Taxes, Net	6.5	6.3	4.8
Parent Company Loss Benefit	(0.2)	(2.1)	(1.4)
Tax Reform Excess ADIT Reversal	(25.5)	(24.5)	(15.5)
Other	(1.5)	(2.8)	(0.4)
Income Tax Expense	$ 5.2	$ 7.5	$ 5.0
Effective Income Tax Rate	4.1 %	5.2 %	5.7 %

SWEPCo

	Years Ended December 31,		
	2020	2019	2018
		(in millions)	
Net Income	$ 183.7	$ 162.2	$ 152.2
Less: Equity Earnings – Dolet Hills	(2.9)	(3.0)	(2.7)
Income Tax Expense (Benefit)	9.4	(4.7)	20.4
Pretax Income	$ 190.2	$ 154.5	$ 169.9
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 39.9	$ 32.4	$ 35.7
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.9	1.9	1.9
Depletion	(3.4)	(3.4)	(3.4)
State and Local Income Taxes, Net	2.7	(1.3)	3.2
AFUDC	(1.5)	(1.4)	(1.3)
Parent Company Loss Benefit	(5.6)	(1.6)	(0.6)
Tax Reform Excess ADIT Reversal	(21.9)	(29.9)	(16.0)
Other	(2.7)	(1.4)	0.9
Income Tax Expense (Benefit)	$ 9.4	$ (4.7)	$ 20.4
Effective Income Tax Rate	4.9 %	(3.0) %	12.0 %

Net Deferred Tax Liability

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant:

AEP		**December 31,**		
		2020		**2019**
		(in millions)		
Deferred Tax Assets	$	3,259.7	$	3,246.1
Deferred Tax Liabilities		(11,500.6)		(10,834.3)
Net Deferred Tax Liabilities	$	(8,240.9)	$	(7,588.2)
Property Related Temporary Differences	$	(7,340.5)	$	(6,602.9)
Amounts Due to Customers for Future Income Taxes		1,075.8		1,173.5
Deferred State Income Taxes		(1,317.6)		(1,198.0)
Securitized Assets		(140.0)		(178.7)
Regulatory Assets		(391.6)		(371.1)
Accrued Nuclear Decommissioning		(626.4)		(557.4)
Net Operating Loss Carryforward		112.9		77.6
Tax Credit Carryforward		323.6		247.2
Operating Lease Liability		183.7		182.6
Investment in Partnership		(362.0)		(446.6)
All Other, Net		241.2		85.6
Net Deferred Tax Liabilities	$	(8,240.9)	$	(7,588.2)

AEP Texas		**December 31,**		
		2020		**2019**
		(in millions)		
Deferred Tax Assets	$	183.6	$	220.0
Deferred Tax Liabilities		(1,200.3)		(1,185.4)
Net Deferred Tax Liabilities	$	(1,016.7)	$	(965.4)
Property Related Temporary Differences	$	(1,039.6)	$	(973.5)
Amounts Due to Customers for Future Income Taxes		114.4		126.7
Deferred State Income Taxes		(29.1)		(27.5)
Securitized Transition Assets		(90.2)		(124.3)
Regulatory Assets		(47.4)		(51.2)
Operating Lease Liability		18.0		17.2
All Other, Net		57.2		67.2
Net Deferred Tax Liabilities	$	(1,016.7)	$	(965.4)

AEPTCo		**December 31,**		
		2020		**2019**
		(in millions)		
Deferred Tax Assets	$	166.5	$	162.9
Deferred Tax Liabilities		(1,073.4)		(980.7)
Net Deferred Tax Liabilities	$	(906.9)	$	(817.8)
Property Related Temporary Differences	$	(937.8)	$	(847.1)
Amounts Due to Customers for Future Income Taxes		118.9		119.9
Deferred State Income Taxes		(98.3)		(86.1)
Net Operating Loss Carryforward		13.2		12.3
All Other, Net		(2.9)		(16.8)
Net Deferred Tax Liabilities	$	(906.9)	$	(817.8)

APCo

	December 31, 2020	December 31, 2019
	(in millions)	
Deferred Tax Assets	$ 500.6	$ 486.2
Deferred Tax Liabilities	(2,250.5)	(2,167.0)
Net Deferred Tax Liabilities	$ (1,749.9)	$ (1,680.8)
Property Related Temporary Differences	$ (1,412.0)	$ (1,420.0)
Amounts Due to Customers for Future Income Taxes	198.3	222.8
Deferred State Income Taxes	(336.5)	(337.2)
Securitized Assets	(44.7)	(49.3)
Regulatory Assets	(114.8)	(71.0)
Operating Lease Liability	16.7	16.5
All Other, Net	(56.9)	(42.6)
Net Deferred Tax Liabilities	$ (1,749.9)	$ (1,680.8)

I&M

	December 31, 2020	December 31, 2019
	(in millions)	
Deferred Tax Assets	$ 989.5	$ 970.5
Deferred Tax Liabilities	(2,053.9)	(1,950.2)
Net Deferred Tax Liabilities	$ (1,064.4)	$ (979.7)
Property Related Temporary Differences	$ (409.2)	$ (430.7)
Amounts Due to Customers for Future Income Taxes	147.9	169.6
Deferred State Income Taxes	(211.1)	(194.4)
Regulatory Assets	(16.5)	(26.9)
Accrued Nuclear Decommissioning	(626.4)	(557.4)
Operating Lease Liability	46.6	61.9
All Other, Net	4.3	(1.8)
Net Deferred Tax Liabilities	$ (1,064.4)	$ (979.7)

OPCo

	December 31, 2020	December 31, 2019
	(in millions)	
Deferred Tax Assets	$ 210.8	$ 202.3
Deferred Tax Liabilities	(1,165.9)	(1,051.6)
Net Deferred Tax Liabilities	$ (955.1)	$ (849.3)
Property Related Temporary Differences	$ (1,016.0)	$ (890.8)
Amounts Due to Customers for Future Income Taxes	121.1	130.2
Deferred State Income Taxes	(40.7)	(35.5)
Regulatory Assets	(53.7)	(48.0)
Operating Lease Liability	19.4	18.3
All Other, Net	14.8	(23.5)
Net Deferred Tax Liabilities	$ (955.1)	$ (849.3)

PSO

	December 31, 2020	December 31, 2019
	(in millions)	
Deferred Tax Assets	$ 239.8	$ 257.4
Deferred Tax Liabilities	(928.3)	(885.7)
Net Deferred Tax Liabilities	$ (688.5)	$ (628.3)
Property Related Temporary Differences	$ (661.8)	$ (627.6)
Amounts Due to Customers for Future Income Taxes	118.5	127.2
Deferred State Income Taxes	(107.7)	(100.4)
Regulatory Assets	(39.1)	(44.6)
Net Operating Loss Carryforward	12.9	10.2
All Other, Net	(11.3)	6.9
Net Deferred Tax Liabilities	$ (688.5)	$ (628.3)

SWEPCo

	December 31, 2020	December 31, 2019
	(in millions)	
Deferred Tax Assets	$ 338.1	$ 359.6
Deferred Tax Liabilities	(1,355.7)	(1,300.5)
Net Deferred Tax Liabilities	$ (1,017.6)	$ (940.9)
Property Related Temporary Differences	$ (985.1)	$ (947.6)
Amounts Due to Customers for Future Income Taxes	162.7	169.8
Deferred State Income Taxes	(214.7)	(200.3)
Regulatory Assets	(26.2)	(30.2)
Net Operating Loss Carryforward	33.4	38.2
All Other, Net	12.3	29.2
Net Deferred Tax Liabilities	$ (1,017.6)	$ (940.9)

AEP System Tax Allocation Agreement

AEP and subsidiaries join in the filing of a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the AEP System subsidiaries with taxable income reducing their current tax expense proportionately. The consolidated NOL of the AEP System is allocated to each company in the consolidated group with taxable losses. With the exception of the allocation of the consolidated AEP System NOL, the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal Income Tax Audit Status

The statute of limitations for the IRS to examine AEP and subsidiaries originally filed federal return has expired for tax years 2016 and earlier. In 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 NOL carryback to 2015 that originated in the 2017 return. As of December 31, 2020, the IRS has not challenged any items on these returns and the IRS is limited in their proposed adjustments to the amount AEP claimed on the amended returns.

Net Income Tax Operating Loss Carryforward

As of December 31, 2020, AEP has no federal net income tax operating loss carryforward. AEP, AEPTCo, I&M, PSO and SWEPCo have state net income tax operating loss carryforwards as indicated in the table below:

Company	State/Municipality	State Net Income Tax Operating Loss Carryforward	Years of Expiration
		(in millions)	
AEP	Arkansas	$ 87.2	2021 - 2028
AEP	Kentucky	163.7	2030 - 2037
AEP	Louisiana	466.8	2025 - 2040
AEP	Oklahoma	569.4	2034 - 2037
AEP	Tennessee	31.1	2028 - 2035
AEP	Virginia	29.4	2025 - 2037
AEP	West Virginia	21.9	2029 - 2037
AEP	Ohio Municipal	649.8	2021 - 2025
AEP	Indiana	145.7	2039
AEP	Colorado	95.7	NA
AEP	Pennsylvania	56.5	2030 - 2040
AEP	New Jersey	60.2	2036 - 2040
AEP	Illinois	15.6	2031
AEP	Michigan	14.9	2029
AEPTCo	Oklahoma	195.4	2034 - 2037
AEPTCo	Ohio Municipal	18.4	2023
I&M	West Virginia	2.5	2032 - 2037
PSO	Oklahoma	354.5	2034 - 2037
SWEPCo	Arkansas	86.4	2021 - 2024
SWEPCo	Louisiana	454.3	2032 - 2037

As of December 31, 2020, AEP recorded a valuation allowance of $9 million, against certain state and municipal net income tax operating loss carryforwards since future taxable income is not expected to be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires. Management anticipates future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires for each state.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2016, 2017 and 2019 resulted in unused federal and state income tax credits. As of December 31, 2020, the Registrants have federal tax credit carryforwards and AEP and PSO have state tax credit carryforwards as indicated in the table below. If these credits are not utilized, federal general business tax credits will expire in the years 2036 through 2040 and state tax credits will remain available indefinitely.

Company	Total Federal Tax Credit Carryforward	Total State Tax Credit Carryforward
	(in millions)	
AEP	$ 323.6	$ 38.4
AEP Texas	1.2	—
AEPTCo	0.1	—
APCo	1.6	—
I&M	9.7	—
OPCo	0.5	—
PSO	0.5	38.4
SWEPCo	1.3	—

The Registrants anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Valuation Allowance

AEP assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective evidence evaluated includes whether AEP has a history of recognizing income, future reversals of existing temporary differences and tax planning strategies.

Valuation allowance activity for the years ended December 31, 2020, 2019 and 2018 was immaterial.

Uncertain Tax Positions

The reconciliations of the beginning and ending amounts of unrecognized tax benefits for AEP are presented below. The amount and activity of unrecognized tax benefits for Registrants Subsidiaries was immaterial for periods presented:

	AEP		
	2020	**2019**	**2018**
		(in millions)	
Balance as of January 1,	$ 24.1	$ 14.6	$ 86.6
Increase – Tax Positions Taken During a Prior Period	0.6	8.8	0.1
Decrease – Tax Positions Taken During a Prior Period	(14.5)	(2.1)	—
Increase – Tax Positions Taken During the Current Year	3.0	2.8	—
Decrease – Tax Positions Taken During the Current Year	—	—	—
Decrease – Settlements with Taxing Authorities	—	—	(71.0)
Decrease – Lapse of the Applicable Statute of Limitations	—	—	(1.1)
Balance as of December 31,	$ 13.2	$ 24.1	$ 14.6

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for AEP as of December 31, 2020, 2019 and 2018 were $12 million, $20 million and $12 million, respectively.

Federal Tax Legislation

In March 2020, the CARES Act was signed into law. The CARES Act includes tax relief provisions such as: (a) an AMT Credit Refund, (b) a 5-year NOL carryback from years 2018-2020 and (c) delayed payment of employer payroll taxes. Pursuant to the CARES Act, AEP, APCo and OPCo requested and in July received refunds of AMT credit of $20 million, $7 million and $9 million, respectively. 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 Act. AEP carried back a 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 $48 million primarily at the Generation & Marketing segment. Management will continue to monitor potential legislation and any impacts to the AMT Credit and NOL refunds that were filed in 2020 pursuant to the CARES Act.

In December 2020, the CAA of 2021 was signed into law. The CAA of 2021 includes: (a) COVID-19 tax relief and tax extender provisions including extensions of time to begin construction on and placed in-service assets generating PTCs and ITCs, (b) 100% deductibility of business meals in 2021 and 2022 and (c) an extension of the work opportunity tax credit. The ITC percentage has been increased for projects starting construction through 2023 and placed in-service by the end of 2025. The PTC has been extended for an additional year, to include projects started in 2021 and completed in 2025. These provisions provide time and flexibility on the construction start and in-service dates.

In September and November 2020, the IRS issued final regulations that provide guidance regarding the additional first-year depreciation deduction under Section 168(k). The final regulations reflect changes as a result of Tax Reform, which affects taxpayers with qualified depreciable property acquired and placed in-service after September 27, 2017. Generally, AEP's regulated utilities will not be eligible for any bonus depreciation for property acquired and placed in-service after December 31, 2017. AEP's competitive businesses will be eligible for 100% expensing.

The IRS issued final regulations in 2020 that provide guidance concerning potential limitations on the deduction of business interest expense. These regulations require an allocation of net interest expense between regulated and competitive businesses within the consolidated tax return. This allocation is based upon net tax basis, and the proposed regulations provide de minimis tests under which all interest is deductible if less than 10% is allocable to the competitive businesses. AEP will deduct materially all business interest expense under this de minimis provision.

On December 30, 2020, the IRS issued regulations that provide guidance on the non-deductibility of certain executives compensation above $1 million under Internal Revenue Code Section 162(m). The regulations clarify the application of rules passed under Tax Reform that expanded the application of Section 162(m) to SEC registered companies that issue either public equity or debt. These rules also expanded the type of compensation and the number of executives subject to this deduction disallowance. AEP limits certain executives' compensation to the $1 million limitation on its federal income tax return.

13. LEASES

The disclosures in this note apply to all Registrants unless indicated otherwise. Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheets.

The Registrants lease property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. AEP does not separate non-lease components from associated lease components. Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain the Registrant will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. AEP has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, the Registrants measure their lease obligation using their estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating lease rentals and finance lease amortization costs are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Effective in 2019, interest on finance lease liabilities is generally charged to Interest Expense. Finance lease interest for periods prior to 2019 were charged to Other Operation and Maintenance expense. Lease costs associated with capital projects are included in Property, Plant and Equipment on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs were as follows:

Year Ended December 31, 2020	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 279.6	$ 17.4	$ 2.6	$ 19.1	$ 101.5	$ 17.1	$ 7.8	$ 9.4
Finance Lease Cost:								
Amortization of Right-of-Use Assets	61.9	6.3	—	7.4	6.5	4.7	3.5	10.9
Interest on Lease Liabilities	15.4	1.5	—	2.7	3.1	0.9	0.7	2.2
Total Lease Rental Costs (a)	$ 356.9	$ 25.2	$ 2.6	$ 29.2	$ 111.1	$ 22.7	$ 12.0	$ 22.5

Year Ended December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 286.0	$ 16.5	$ 2.5	$ 19.5	$ 93.1	$ 18.0	$ 6.8	$ 8.0
Finance Lease Cost:								
Amortization of Right-of-Use Assets	70.8	5.1	0.1	6.7	5.7	3.5	3.1	11.0
Interest on Lease Liabilities	16.4	1.4	—	2.9	2.9	0.7	0.6	2.9
Total Lease Rental Costs (a)	$ 373.2	$ 23.0	$ 2.6	$ 29.1	$ 101.7	$ 22.2	$ 10.5	$ 21.9

Year Ended December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Cost	$ 245.0	$ 13.6	$ 2.7	$ 18.2	$ 89.2	$ 10.7	$ 5.7	$ 6.5
Finance Lease Cost:								
Amortization of Right-of-Use Assets	62.4	4.8	0.1	7.0	6.6	3.9	3.2	11.2
Interest on Lease Liabilities	16.4	1.2	—	3.0	3.3	0.5	0.4	3.2
Total Lease Rental Costs	$ 323.8	$ 19.6	$ 2.8	$ 28.2	$ 99.1	$ 15.1	$ 9.3	$ 20.9

(a) Excludes variable and short-term lease costs, which were immaterial for the twelve months ended December 31, 2020 and December 31, 2019.

Supplemental information related to leases are shown in the tables below:

December 31, 2020	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	5.30	6.51	2.01	6.27	3.50	7.44	7.03	7.54
Finance Leases	5.43	6.07	0.00	5.75	5.79	5.90	6.16	4.95
Weighted-Average Discount Rate:								
Operating Leases	3.44 %	3.60 %	1.51 %	3.48 %	3.42 %	3.60 %	3.39 %	3.45 %
Finance Leases	5.68 %	4.39 %	— %	7.33 %	8.29 %	4.25 %	4.35 %	4.77 %

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
Weighted-Average Remaining Lease Term (years):								
Operating Leases	5.23	6.93	2.25	6.28	3.91	7.94	7.07	6.64
Finance Leases	5.85	6.69	0.25	6.12	6.55	6.49	6.23	5.16
Weighted-Average Discount Rate:								
Operating Leases	3.60 %	3.77 %	3.14 %	3.64 %	3.45 %	3.76 %	3.64 %	3.76 %
Finance Leases	5.98 %	4.62 %	9.33 %	8.08 %	8.47 %	4.54 %	4.62 %	5.01 %

Year Ended December 31, 2020	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Cash paid for amounts included in the measurement of lease liabilities:								
Operating Cash Flows Used for Operating Leases	$ 280.3	$ 17.1	$ 2.6	$ 19.2	$ 102.2	$ 16.9	$ 7.7	$ 9.4
Operating Cash Flows Used for Finance Leases	15.4	1.5	—	2.7	3.1	0.9	0.7	2.2
Financing Cash Flows Used for Finance Leases	61.7	6.3	—	7.4	6.5	4.7	3.5	10.9
Non-cash Acquisitions Under Operating Leases	$ 161.7	$ 15.8	$ 1.8	$ 16.2	$ 18.1	$ 18.1	$ 12.3	$ 18.4

Year Ended December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Cash paid for amounts included in the measurement of lease liabilities:								
Operating Cash Flows Used for Operating Leases	$ 284.7	$ 15.3	$ 2.4	$ 19.0	$ 94.3	$ 18.0	$ 6.7	$ 7.9
Operating Cash Flows Used for Finance Leases	16.4	1.4	—	2.9	3.1	0.7	0.6	3.0
Financing Cash Flows Used for Finance Leases	70.7	5.1	—	6.7	5.7	3.5	3.1	11.0
Non-cash Acquisitions Under Operating Leases	$ 125.0	$ 13.8	$ 0.6	$ 10.2	$ 18.7	$ 35.4	$ 8.2	$ 11.4

The following tables show property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on the balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

December 31, 2020	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 138.2	$ —	$ —	$ 42.8	$ 28.8	$ —	$ 0.7	$ 37.7
Other Property, Plant and Equipment	322.8	49.7	—	20.3	40.2	31.4	23.0	52.4
Total Property, Plant and Equipment	461.0	49.7	—	63.1	69.0	31.4	23.7	90.1
Accumulated Amortization	176.8	16.6	—	21.4	27.3	9.8	8.7	36.5
Net Property, Plant and Equipment Under Finance Leases	$ 284.2	$ 33.1	$ —	$ 41.7	$ 41.7	$ 21.6	$ 15.0	$ 53.6
Obligations Under Finance Leases:								
Noncurrent Liability	$ 231.0	$ 26.8	$ —	$ 34.4	$ 35.3	$ 16.9	$ 11.9	$ 44.6
Liability Due Within One Year	58.1	6.3	—	7.3	6.4	4.7	3.1	10.7
Total Obligations Under Finance Leases	$ 289.1	$ 33.1	$ —	$ 41.7	$ 41.7	$ 21.6	$ 15.0	$ 55.3

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Finance Leases:								
Generation	$ 131.6	$ —	$ —	$ 39.9	$ 28.8	$ —	$ 0.6	$ 34.1
Other Property, Plant and Equipment	323.0	45.9	0.2	18.9	39.3	27.3	21.6	51.6
Total Property, Plant and Equipment	454.6	45.9	0.2	58.8	68.1	27.3	22.2	85.7
Accumulated Amortization	151.5	11.8	0.2	17.0	23.0	7.2	7.1	28.4
Net Property, Plant and Equipment Under Finance Leases	$ 303.1	$ 34.1	$ —	$ 41.8	$ 45.1	$ 20.1	$ 15.1	$ 57.3
Obligations Under Finance Leases:								
Noncurrent Liability	$ 249.2	$ 28.2	$ —	$ 35.0	$ 38.8	$ 16.2	$ 11.9	$ 47.1
Liability Due Within One Year	57.6	5.9	—	6.8	6.3	3.9	3.2	10.5
Total Obligations Under Finance Leases	$ 306.8	$ 34.1	$ —	$ 41.8	$ 45.1	$ 20.1	$ 15.1	$ 57.6

December 31, 2020	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Assets	$ 866.4	$ 84.1	$ 1.6	$ 78.8	$ 218.1	$ 92.0	$ 42.6	$ 48.5
Obligations Under Operating Leases:								
Noncurrent Liability	$ 638.4	$ 71.0	$ 0.4	$ 64.4	$ 135.9	$ 79.5	$ 36.2	$ 44.1
Liability Due Within One Year	241.3	14.5	1.2	14.9	85.6	13.1	6.5	7.9
Total Obligations Under Operating Leases	$ 879.7	$ 85.5	$ 1.6	$ 79.3	$ 221.5	$ 92.6	$ 42.7	$ 52.0

December 31, 2019	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Operating Lease Assets	$ 957.4	$ 81.8	$ 3.8	$ 78.5	$ 294.9	$ 88.0	$ 36.8	$ 40.5
Obligations Under Operating Leases:								
Noncurrent Liability	$ 734.6	$ 71.1	$ 1.9	$ 64.0	$ 211.6	$ 76.0	$ 31.0	$ 34.7
Liability Due Within One Year	234.1	12.0	2.1	15.2	87.3	12.5	5.8	6.5
Total Obligations Under Operating Leases	$ 968.7	$ 83.1	$ 4.0	$ 79.2	$ 298.9	$ 88.5	$ 36.8	$ 41.2

Future minimum lease payments consisted of the following as of December 31, 2020:

Finance Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2021	$ 72.2	$ 7.6	$ —	$ 9.9	$ 9.3	$ 5.5	$ 3.6	$ 13.1
2022	64.0	6.9	—	9.4	8.6	4.6	3.1	11.8
2023	56.2	6.2	—	8.7	7.9	3.9	2.7	10.9
2024	63.5	5.4	—	8.1	11.1	3.3	2.3	15.3
2025	32.7	4.0	—	7.0	5.5	2.2	1.6	5.7
Later Years	48.9	7.8	—	6.4	12.2	4.9	3.8	5.8
Total Future Minimum Lease Payments	337.5	37.9	—	49.5	54.6	24.4	17.1	62.6
Less: Imputed Interest	48.4	4.8	—	7.8	12.9	2.8	2.1	7.3
Estimated Present Value of Future Minimum Lease Payments	$ 289.1	$ 33.1	$ —	$ 41.7	$ 41.7	$ 21.6	$ 15.0	$ 55.3

Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2021	$ 270.8	$ 17.5	$ 1.2	$ 17.7	$ 92.5	$ 16.6	$ 7.9	$ 10.1
2022	263.3	16.4	0.2	17.0	92.5	16.0	7.6	9.6
2023	94.2	14.8	0.1	14.2	11.4	14.9	7.3	8.4
2024	81.6	13.3	0.1	11.3	10.0	13.2	6.5	6.9
2025	68.0	10.9	—	8.5	8.9	11.5	5.4	5.8
Later Years	193.0	23.9	—	20.0	21.8	34.0	13.3	17.4
Total Future Minimum Lease Payments	970.9	96.8	1.6	88.7	237.1	106.2	48.0	58.2
Less: Imputed Interest	91.2	11.3	—	9.4	15.6	13.6	5.3	6.2
Estimated Present Value of Future Minimum Lease Payments	$ 879.7	$ 85.5	$ 1.6	$ 79.3	$ 221.5	$ 92.6	$ 42.7	$ 52.0

Future minimum lease payments consisted of the following as of December 31, 2019:

Finance Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2020	$ 72.7	$ 7.3	$ —	$ 9.6	$ 9.4	$ 4.7	$ 3.8	$ 12.9
2021	64.9	6.7	—	8.9	8.7	4.3	3.2	11.9
2022	56.4	6.0	—	8.2	8.0	3.4	2.6	10.6
2023	49.6	5.4	—	7.7	7.5	2.8	2.3	9.8
2024	57.4	4.6	—	7.1	10.8	2.4	1.8	14.2
Later Years	64.4	9.8	—	9.8	16.4	5.7	3.8	6.8
Total Future Minimum Lease Payments	365.4	39.8	—	51.3	60.8	23.3	17.5	66.2
Less: Imputed Interest	58.6	5.7	—	9.5	15.7	3.2	2.4	8.6
Estimated Present Value of Future Minimum Lease Payments	$ 306.8	$ 34.1	$ —	$ 41.8	$ 45.1	$ 20.1	$ 15.1	$ 57.6

Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2020	$ 269.9	$ 16.0	$ 2.2	$ 18.3	$ 97.0	$ 16.2	$ 7.3	$ 8.6
2021	253.6	15.3	1.2	15.7	92.9	14.2	6.4	8.2
2022	245.6	14.2	0.6	14.7	92.8	13.5	6.0	7.6
2023	74.8	13.0	0.1	11.9	10.1	12.3	5.6	6.4
2024	62.0	11.4	—	9.0	8.6	10.7	4.8	5.0
Later Years	169.7	26.0	—	20.0	21.0	36.5	12.0	11.8
Total Future Minimum Lease Payments	1,075.6	95.9	4.1	89.6	322.4	103.4	42.1	47.6
Less: Imputed Interest	106.9	12.8	0.1	10.4	23.5	14.9	5.3	6.4
Estimated Present Value of Future Minimum Lease Payments	$ 968.7	$ 83.1	$ 4.0	$ 79.2	$ 298.9	$ 88.5	$ 36.8	$ 41.2

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 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	$ 50.3
AEP Texas	11.7
APCo	6.6
I&M	4.4
OPCo	8.1
PSO	4.8
SWEPCo	5.4

Rockport Lease (Applies to AEP and I&M)

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors. In the first quarter of 2019, in accordance with ASU 2016-02, the $37 million unamortized gain ($15 million related to I&M) associated with the sale-and-leaseback of the Plant was recognized as an adjustment to equity. The adjustment to equity was then reclassified to regulatory liabilities in accordance with accounting guidance for “Regulated Operations” as AEGCo and I&M will continue to provide the benefit of the unamortized gain to customers in future periods.

The Owner Trustee owns the Plant and leases equal portions to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years and at the end of the lease term, AEGCo and I&M have the option to renew the lease at a rate that approximates fair value. In November 2020, management announced that AEP will not renew the lease when it expires in 2022. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2020 were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2021	$ 147.8	$ 73.9
2022	147.6	73.8
Total Future Minimum Lease Payments	$ 295.4	$ 147.7

(a) AEP’s future minimum lease payments include equal shares from AEGCo and I&M.

AEPRO Boat and Barge Leases (Applies to AEP)

In 2015, AEP sold its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. Certain boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the respective lessors, ensuring future payments under such leases with maturities up to 2027. As of December 31, 2020, the maximum potential amount of future payments required under the guaranteed leases was $48 million. Under the terms of certain of the arrangements, upon the lessors exercising their rights after an event of default by the nonaffiliated party, AEP is entitled to enter into new lease arrangements as a lessee that would have substantially the same terms as the existing leases. Alternatively, for the arrangements with one of the lessors, upon an event of default by the nonaffiliated party and the lessor exercising its rights, payment to the lessor would allow AEP to step into the lessor’s rights as well as obtaining title to the assets. Under either situation, AEP would have the ability to utilize the assets in the normal course of barging operations. AEP would also have the right to sell the acquired assets for which it obtained title. As of December 31, 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.

Lessor Activity

The Registrants’ lessor activity was immaterial as of and for the twelve months ended December 31, 2020 and December 31, 2019, respectively.

14. FINANCING ACTIVITIES

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

Common Stock (Applies to AEP)

The following table is a reconciliation of common stock share activity:

Shares of AEP Common Stock	Issued	Held in Treasury	
Balance, December 31, 2017	512,210,644	20,205,046	
Issued	1,239,392	—	
Treasury Stock Reissued	—	(886)	(a)
Balance, December 31, 2018	513,450,036	20,204,160	
Issued	923,595	—	
Balance, December 31, 2019	514,373,631	20,204,160	
Issued	2,434,723	—	
Balance, December 31, 2020	516,808,354	20,204,160	

(a) Reissued Treasury Stock used to fulfill share commitments related to AEP's Share-based Compensation. See "Shared-based Compensation Plans" section of Note 15 for additional information.

At-the-Market (ATM) Program

In November 2020, AEP filed a prospectus supplement and executed an Equity Distribution Agreement (EDA), pursuant to which AEP may sell, from time to time, up to an aggregate of $1 billion of its common stock through an ATM offering program, including an equity forward sales component. The compensation paid to the selling agents by AEP may be up to 2% of the gross offering proceeds of the shares. There were no issuances under the ATM program for the year ended December 31, 2020.

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

The following table details long-term debt outstanding:

Company	Maturity	Weighted-Average Interest Rate as of December 31, 2020	Interest Rate Ranges as of December 31, 2020	Interest Rate Ranges as of December 31, 2019	Outstanding as of December 31, 2020	Outstanding as of December 31, 2019
AEP					(in millions)	
Senior Unsecured Notes	2020-2050	3.97%	0.70%-8.13%	2.15%-8.13%	$ 25,116.1	$ 21,180.7
Pollution Control Bonds (a)	2020-2036 (b)	2.39%	0.18%-4.63%	1.35%-5.38%	1,936.7	1,998.8
Notes Payable – Nonaffiliated (c)	2020-2032	2.34%	0.84%-6.37%	2.42%-6.37%	239.1	234.3
Securitization Bonds	2020-2029 (d)	2.78%	2.01%-3.77%	1.98%-5.31%	716.4	1,025.1
Spent Nuclear Fuel Obligation (e)					281.2	279.8
Junior Subordinated Notes (f)	2022-2023	2.32%	1.30%-3.40%	3.40%	1,624.1	787.8
Other Long-term Debt	2020-2059	1.59%	0.81%-13.72%	1.15%-13.718%	1,158.9	1,219.0
Total Long-term Debt Outstanding					$ 31,072.5	$ 26,725.5
AEP Texas						
Senior Unsecured Notes	2022-2050	3.70%	2.10%-6.76%	2.40%-6.76%	$ 3,687.6	$ 3,090.9
Pollution Control Bonds	2020-2030 (b)	3.42%	0.90%-4.55%	1.75%-4.55%	439.7	490.3
Securitization Bonds	2020-2029 (d)	2.55%	2.06%-2.84%	1.98%-5.31%	492.6	776.8
Other Long-term Debt	2022-2059	1.41%	1.40%-4.50%	3.05%-4.50%	200.5	200.4
Total Long-term Debt Outstanding					$ 4,820.4	$ 4,558.4
AEPTCo						
Senior Unsecured Notes	2021-2050	3.83%	3.10%-5.52%	3.10%-5.52%	$ 3,948.5	$ 3,427.3
Total Long-term Debt Outstanding					$ 3,948.5	$ 3,427.3
APCo						
Senior Unsecured Notes	2021-2050	4.94%	3.30%-7.00%	3.30%-7.00%	$ 3,937.2	$ 3,442.7
Pollution Control Bonds (a)	2020-2036 (b)	1.77%	0.19%-4.63%	1.67%-5.38%	546.3	546.1
Securitization Bonds	2023-2028 (d)	3.29%	2.01%-3.77%	2.008%-3.772%	223.8	248.3
Other Long-term Debt	2022-2026	1.51%	1.32%-13.72%	2.97%-13.718%	126.8	126.7
Total Long-term Debt Outstanding					$ 4,834.1	$ 4,363.8
I&M						
Senior Unsecured Notes	2023-2048	4.38%	3.20%-6.05%	3.20%-6.05%	$ 2,152.2	$ 2,150.7
Pollution Control Bonds (a)	2021-2025 (b)	2.21%	0.18%-3.05%	1.79%-3.05%	240.5	240.0
Notes Payable – Nonaffiliated (c)	2020-2025	1.06%	0.84%-1.29%	2.42%-2.80%	146.7	168.7
Spent Nuclear Fuel Obligation (e)					281.2	279.8
Other Long-term Debt	2021-2025	1.49%	1.28%-6.00%	2.93%-6.00%	209.3	211.0
Total Long-term Debt Outstanding					$ 3,029.9	$ 3,050.2
OPCo						
Senior Unsecured Notes	2021-2049	4.82%	2.60%-6.60%	4.00%-6.60%	$ 2,429.4	$ 2,081.0
Other Long-term Debt	2028	1.15%	1.15%	1.15%	0.8	1.0
Total Long-term Debt Outstanding					$ 2,430.2	$ 2,082.0
PSO						
Senior Unsecured Notes	2021-2049	4.55%	3.05%-6.63%	3.05%-6.625%	$ 1,246.3	$ 1,245.6
Pollution Control Bonds	2020			4.45%	—	12.7
Other Long-term Debt	2022-2027	1.47%	1.42%-3.00%	3.00%-3.20%	127.5	127.9
Total Long-term Debt Outstanding					$ 1,373.8	$ 1,386.2
SWEPCo						
Senior Unsecured Notes	2022-2048	4.04%	2.75%-6.20%	2.75%-6.20%	$ 2,430.8	$ 2,428.9
Notes Payable – Nonaffiliated (c)	2024-2032	5.30%	4.58%-6.37%	4.58%-6.37%	62.4	65.6
Other Long-term Debt	2021-2035	2.99%	2.25%-4.68%	3.08%-4.68%	143.2	161.1
Total Long-term Debt Outstanding					$ 2,636.4	$ 2,655.6

(a) For certain series of Pollution Control Bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets.

(b) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Dates represent the scheduled final payment dates for the securitization bonds. The legal maturity date is one to two years later. These bonds have been classified for maturity and repayment purposes based on the scheduled final payment date.

(e) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of SNF. See "Spent Nuclear Fuel Disposal" section of Note 6 for additional information.

(f) See "Equity Units" section below for additional information.

As of December 31, 2020, outstanding long-term debt was payable as follows:

	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)				
2021	$ 2,086.1		$ 88.7	$ 50.0	$ 518.3	$ 369.6	$ 500.1	$ 0.5	$ 106.2
2022	3,538.4	(a)	716.0	104.0	355.4	45.1	0.1	375.5	281.2
2023	2,659.3	(b)	278.5	60.0	26.6	273.9	0.1	0.5	6.2
2024	723.4		96.0	95.0	113.5	8.1	0.1	0.6	31.2
2025	1,726.3		324.5	90.0	443.9	151.5	0.1	125.6	6.2
After 2025	20,599.2		3,357.0	3,591.0	3,418.3	2,206.2	1,950.3	875.8	2,225.5
Principal Amount	31,332.7		4,860.7	3,990.0	4,876.0	3,054.4	2,450.8	1,378.5	2,656.5
Unamortized Discount, Net and Debt Issuance Costs	(260.2)		(40.3)	(41.5)	(41.9)	(24.5)	(20.6)	(4.7)	(20.1)
Total Long-term Debt Outstanding	$ 31,072.5		$ 4,820.4	$ 3,948.5	$ 4,834.1	$ 3,029.9	$ 2,430.2	$ 1,373.8	$ 2,636.4

(a) Amount includes $805 million of Junior Subordinated Notes. See "Equity Units" section below for additional information.
(b) Amount includes $850 million of Junior Subordinated Notes. See "Equity Units" section below for additional information.

Long-term Debt Subsequent Events

In January and February 2021, I&M retired $8 million and $7 million, respectively, of Notes Payable related to DCC Fuel.

In January 2021, OPCo issued $450 million of Senior Unsecured Notes.

In January 2021, PSO issued $400 million of variable rate Other Long-term Debt due in 2022, which it used to retire $250 million of Senior Unsecured Notes in February 2021.

In January and February 2021, Transource Energy issued $5 million and $9 million, respectively, of variable rate Other Long-term Debt due in 2023.

In February 2021, AEP Texas retired $11 million of Securitization Bonds.

In February 2021, APCo retired $12 million of Securitization Bonds.

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 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 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 issued 16.1 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $805 million. Net proceeds from the issuance were approximately $785 million. The proceeds were used to support AEP's overall capital expenditure plans including the acquisition of Sempra Renewables LLC.

Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 3.40% Junior Subordinated Notes (notes) due in 2024 and a forward equity purchase contract which settles after three years in 2022. The notes are expected to be remarketed in 2022, at which time the interest rate will reset at the then-current market rate. Investors may choose to remarket their notes to receive the remarketing proceeds and use those funds to settle the forward equity purchase contract, or accept the remarketed debt and use other funds for the equity purchase. If the remarketing is unsuccessful, investors have the right to put their notes to AEP at a price equal to the principal. The Equity Units carry an annual distribution rate of 6.125%, which is comprised of a quarterly coupon rate of interest of 3.40% and a quarterly forward equity purchase contract payment of 2.725%.

Each forward equity purchase contract obligates the holder to purchase, and AEP to sell, for $50 a number of shares in common stock in accordance with the conversion ratios set forth below (subject to an anti-dilution adjustment):

- If the AEP common stock market price is equal to or greater than $99.58: 0.5021 shares per contract.
- If the AEP common stock market price is less than $99.58 but greater than $82.98: a number of shares per contract equal to $50 divided by the applicable market price. The holder receives a variable number of shares at $50.
- If the AEP common stock market price is less than or equal to $82.98: 0.6026 shares per contract.

A holder's ownership interest in the notes is pledged to AEP to secure the holder's obligation under the related forward equity purchase contract. If a holder of the forward equity purchase contract chooses at any time to no longer be a holder of the notes, such holder's obligation under the forward equity purchase contract must be secured by a U.S. Treasury security which must be equal to the aggregate principal amount of the notes.

At the time of issuance, the $805 million of notes were recorded within Long-term Debt on the balance sheets. The present value of the purchase contract payments of $62 million were recorded in Deferred Credits and Other Noncurrent Liabilities with a current portion in Other Current Liabilities at the time of issuance, representing the obligation to make forward equity contract payments, with an offsetting reduction to Paid-in Capital. The difference between the face value and present value of the purchase contract payments will be accreted to Interest Expense on the statements of income over the three year period ending in 2022. The liability recorded for the contract payments is considered non-cash and excluded from the statements of cash flows. Until settlement of the forward equity purchase contract, earnings per-share dilution resulting from the equity unit issuance will be determined under the treasury stock method. The maximum amount of shares AEP will be required to issue to settle the purchase contract is 9,701,860 shares (subject to an anti-dilution adjustment).

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. AEPTCo's contractually-defined priority debt was 1.6% of consolidated tangible net assets as of December 31, 2020. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreement.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. The Federal Power Act also creates a reserve on retained earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to AGR, APCo and I&M.

Certain AEP subsidiaries have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for certain AEP subsidiaries is through the Federal Power Act restriction, while for other AEP subsidiaries the most restrictive dividend limitation is through the credit agreements. As of December 31, 2020, the maximum amount of restricted net assets of AEP's subsidiaries that may not be distributed to the Parent in the form of a loan, advance or dividend was $14 billion.

The Federal Power Act restriction limits the ability of the AEP subsidiaries owning hydroelectric generation to pay dividends out of retained earnings. Additionally, the credit agreement covenant restrictions can limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. As of December 31, 2020, the amount of any such restrictions were as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Restricted Retained Earnings	$ 2,369.5 (a)	$ 694.0	$ —	$ 175.1	$ 519.7	$ —	$ 182.3	$ 571.9

(a) Includes the restrictions of consolidated and non-consolidated subsidiaries.

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements. As of December 31, 2020, AEP had $7.1 billion of available retained earnings to pay dividends to common shareholders. AEP paid $1.4 billion, $1.3 billion and $1.3 billion of dividends to common shareholders for the years ended December 31, 2020, 2019 and 2018, respectively.

Lines of Credit and Short-term Debt (Applies to AEP and SWEPCo)

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. As of December 31, 2020, AEP had a $4 billion revolving credit facility to support its commercial paper program. The commercial paper program for the year ended 2020, had a weighted-average interest rate of 1.28% and a maximum amount outstanding of $3 billion. AEP's outstanding short-term debt was as follows:

		December 31,			
		2020		2019	
Company	Type of Debt	Outstanding Amount (in millions)	Interest Rate (a)	Outstanding Amount (in millions)	Interest Rate (a)
AEP	Securitized Debt for Receivables (b)	$ 592.0	0.85 %	$ 710.0	2.42 %
AEP	Commercial Paper	1,852.3	0.29 %	2,110.0	2.10 %
SWEPCo	Notes Payable	35.0	2.55 %	18.3	3.29 %
	Total Short-term Debt	$ 2,479.3		$ 2,838.3	

(a) Weighted-average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Corporate Borrowing Program – AEP System (Applies to Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of December 31, 2020 and 2019 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2020:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2020	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 320.4	$ 313.4	$ 132.0	$ 139.0	$ (67.1)	$ 500.0	
AEPTCo	358.4	259.7	116.3	55.0	(155.4)	820.0	(a)
APCo	434.3	189.0	242.8	76.3	2.8	500.0	
I&M	218.6	13.4	114.5	13.3	(89.7)	500.0	
OPCo	353.9	32.8	182.4	25.2	(259.2)	500.0	
PSO	155.4	57.1	72.3	28.4	(155.4)	300.0	
SWEPCo	178.9	—	113.0	—	(124.6)	350.0	

Year Ended December 31, 2019:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2019	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 390.7	$ 213.1	$ 239.3	$ 194.4	$ 199.7	$ 500.0	
AEPTCo	374.9	244.4	152.0	52.8	(119.0)	795.0	(a)
APCo	270.0	232.2	115.9	51.9	(214.6)	500.0	
I&M	158.8	66.0	71.5	16.2	(101.2)	500.0	
OPCo	291.2	178.6	129.2	50.1	(131.0)	500.0	
PSO	140.5	215.6	63.9	98.3	38.8	300.0	
SWEPCo	105.1	81.4	53.3	13.6	(59.9)	350.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above tables does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of December 31, 2020 and 2019 are included in Advances to Affiliates on each subsidiaries' balance sheets. The Nonutility Money Pool participants' money pool activity is described in the following tables:

Year Ended December 31, 2020:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2020
		(in millions)	
AEP Texas	$ 7.5	$ 7.1	$ 7.1
SWEPCo	2.1	2.1	2.1

Year Ended December 31, 2019:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2019
		(in millions)	
AEP Texas	$ 8.0	$ 7.7	$ 7.5
SWEPCo	2.1	2.0	2.1

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of outstanding loans to and borrowings from AEP as of December 31, 2020 and 2019 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets. AEPTCo's direct financing activities with AEP and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2020:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2020	Loans to AEP as of December 31, 2020	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 1.4	$ 215.3	$ 1.3	$ 132.6	$ 1.2	$ 109.0	$ 50.0	(a)

Year Ended December 31, 2019:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2019	Loans to AEP as of December 31, 2019	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 1.3	$ 153.5	$ 1.3	$ 68.0	$ 1.3	$ 68.7	$ 75.0	(a)

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Years Ended December 31,		
	2020	2019	2018
Maximum Interest Rate	2.70 %	3.43 %	2.97 %
Minimum Interest Rate	0.27 %	1.77 %	1.81 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Years Ended December 31,			Average Interest Rate for Funds Loaned to the Utility Money Pool for the Years Ended December 31,		
Company	**2020**	**2019**	**2018**	**2020**	**2019**	**2018**
AEP Texas	1.51 %	2.63 %	2.26 %	0.81 %	2.03 %	2.29 %
AEPTCo	1.29 %	2.64 %	2.27 %	1.99 %	2.41 %	2.10 %
APCo	2.12 %	2.45 %	2.26 %	0.85 %	2.66 %	2.21 %
I&M	1.07 %	2.34 %	2.16 %	1.18 %	2.60 %	2.08 %
OPCo	0.99 %	2.67 %	2.18 %	2.06 %	2.68 %	2.47 %
PSO	0.92 %	2.85 %	2.27 %	1.95 %	2.27 %	1.98 %
SWEPCo	1.27 %	2.72 %	2.31 %	— %	2.22 %	2.00 %

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool are summarized in the following table:

Year Ended December 31,	Company	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
2020	AEP Texas	2.70 %	0.27 %	1.18 %
2020	SWEPCo	2.70 %	0.27 %	1.18 %
2019	AEP Texas	3.02 %	1.91 %	2.56 %
2019	SWEPCo	3.02 %	1.91 %	2.55 %
2018	AEP Texas	2.97 %	1.83 %	2.36 %
2018	SWEPCo	2.97 %	1.83 %	2.36 %

AEPTCo's maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following table:

Year Ended December 31,	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
2020	2.70 %	0.27 %	2.70 %	0.27 %	1.20 %	1.13 %
2019	3.02 %	1.91 %	3.02 %	1.91 %	2.55 %	2.51 %
2018	2.97 %	1.76 %	2.97 %	1.76 %	2.36 %	2.36 %

Interest expense and interest income related to the Utility Money Pool, Nonutility Money Pool and direct borrowing financing relationship are included in Interest Expense and Interest Income, respectively, on each of the Registrant Subsidiaries' statements of income. The interest expense and interest income related to the corporate borrowing programs were immaterial for the years ended December 31, 2020, 2019 and 2018.

Credit Facilities

See "Letters of Credit" section of Note 6 for additional information.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement that provides a commitment of $750 million from bank conduits to purchase receivables and expires in 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 December 31, 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, the affiliated utility subsidiary would no longer participate in the receivables securitization agreement and the Registrants would need to rely on additional sources of funding for operation and working capital, which may adversely impact liquidity. The receivables that are ineligible under the receivables securitization agreement are financed with short-term debt at AEP Credit.

Accounts receivable information for AEP Credit was as follows:

	Years Ended December 31,		
	2020	2019	2018
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	0.85 %	2.42 %	2.16 %
Net Uncollectible Accounts Receivable Written Off	$ 15.3	$ 26.6	$ 27.6

	December 31,	
	2020	2019
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 958.4	$ 841.8
Short-term – Securitized Debt of Receivables	592.0	710.0
Delinquent Securitized Accounts Receivable	62.3	39.6
Bad Debt Reserves Related to Securitization	60.0	32.1
Unbilled Receivables Related to Securitization	296.8	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 agreement were:

Company	December 31, 2020	2019
	(in millions)	
APCo	$ 136.0	$ 120.9
I&M	170.5	141.8
OPCo	398.8	330.3
PSO	85.0	101.1
SWEPCo	158.6	125.2

The fees paid to AEP Credit for customer accounts receivable sold were:

Company	Years Ended December 31, 2020	2019	2018
		(in millions)	
APCo	$ 5.2	$ 7.4	$ 7.0
I&M	7.9	11.1	9.2
OPCo	24.1	27.1	26.3
PSO	4.8	7.8	7.9
SWEPCo	6.7	10.2	8.9

The proceeds on the sale of receivables to AEP Credit were:

Company	Years Ended December 31, 2020	2019	2018
		(in millions)	
APCo	$ 1,272.9	$ 1,310.3	$ 1,421.0
I&M	1,891.8	1,824.2	1,843.0
OPCo	2,366.2	2,293.6	2,674.5
PSO	1,221.0	1,442.5	1,484.6
SWEPCo	1,593.8	1,618.5	1,736.1

15. STOCK-BASED COMPENSATION

The disclosures in this note apply to AEP only. The impact of AEP's share-based compensation plans is insignificant to the financial statements of the Registrant Subsidiaries.

Awards under AEP's long-term incentive plan may be granted to employees and directors. The Amended and Restated American Electric Power System Long-Term Incentive Plan (Prior Plan), was replaced prospectively for new grants by the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP) effective in April 2015. The 2015 LTIP was subsequently amended in September 2016. The 2015 LTIP provides for a maximum of 10 million AEP common shares to be available for grant to eligible employees and directors. As of December 31, 2020, 6,712,148 shares remained available for issuance under the 2015 LTIP. No new awards may be granted under the Prior Plan. The 2015 LTIP awards may be stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards. Shares issued pursuant to a stock option or a stock appreciation right reduce the shares remaining available for grants under the 2015 LTIP by 0.286 of a share. Each share issued for any other award that settles in AEP stock reduces the shares remaining available for grants under the 2015 LTIP by one share. Cash settled awards do not reduce the number of shares remaining available under the 2015 LTIP. The following sections provide further information regarding each type of stock-based compensation award granted under these plans.

Performance Shares

Performance units granted prior to 2017 were settled in cash rather than AEP common stock and did not reduce the number of shares remaining available under the 2015 LTIP. Those performance units had a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. Performance shares granted in and after 2017 are settled in AEP common stock and reduce the aggregate share authorization. In all cases the number of performance shares held at the end of the three-year performance period is multiplied by the performance score for such period to determine the actual number of performance shares that participants realize. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the Human Resources Committee of AEP's Board of Directors (HR Committee).

Certain employees must satisfy a minimum stock ownership requirement. If those employees have not met their stock ownership requirement, a portion or all of their performance shares are mandatorily deferred as AEP career shares to the extent needed to meet their stock ownership requirement. AEP career shares are a form of non-qualified deferred compensation that has a value equivalent to a share of AEP common stock. AEP career shares are settled in AEP common stock after the participant's termination of employment.

AEP career shares are recorded in Paid-in Capital on the balance sheets. Amounts equivalent to cash dividends on both performance shares and AEP career shares accrue as additional shares. Management records compensation cost for performance shares over an approximately three-year vesting period. Performance shares are recorded as mezzanine equity on the balance sheets until the vesting date and compensation cost is calculated at fair value based on metrics for each grant. Performance shares granted in 2020 had three performance metrics: (a) three-year cumulative operating earnings per-share with a 50% weight, (b) total shareholder return with a 40% weight and (c) non-emitting generation capacity as a percentage of total owned and purchased capacity with a 10% weight. Performance shares granted prior to 2020 had two equally-weighted performance metrics: (a) three-year cumulative operating earnings per-share and (b) total shareholder return. The three-year cumulative operating earnings per-share metric and non-emitting generating capacity metric are adjusted quarterly for changes in performance relative to a target approved by the HR Committee. The total shareholder return metric is measured relative to a peer group of similar companies and is based on a third-party Monte Carlo valuation. The value related to this metric does not change over the three-year vesting period.

The HR Committee awarded performance shares and reinvested dividends on outstanding performance shares and AEP career shares as follows:

Performance Shares	Years Ended December 31, 2020	2019	2018
Awarded Shares (in thousands)	424.8	535.0	581.4
Weighted-Average Share Fair Value at Grant Date	$ 116.56	$ 83.21	$ 67.21
Vesting Period (in years)	3	3	3

Performance Shares and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2020	2019	2018
Awarded Shares (in thousands) (a)	73.4	66.4	80.2
Weighted-Average Fair Value at Grant Date	$ 84.87	$ 88.73	$ 70.58
Vesting Period (in years)	(b)	(b)	(b)

(a) All awarded dividends in both 2020 and 2019 were equity awards and awarded dividends in 2018 were a mix of equity awards and liability awards.

(b) The vesting period for the reinvested dividends on performance shares is equal to the remaining life of the related performance shares. Dividends on AEP career shares vest immediately when the dividend is awarded but are not settled in AEP common stock until after the participant's AEP employment ends.

Performance scores and final awards are determined and approved by the HR Committee in accordance with the pre-established performance measures within approximately two months after the end of the performance period.

The certified performance scores and shares earned for the three-year periods were as follows:

Performance Shares	Years Ended December 31, 2020	2019	2018
Certified Performance Score	128.2 %	132.7 %	136.7 %
Performance Shares Earned	757,858	792,897	820,780
Performance Shares Mandatorily Deferred as AEP Career Shares	13,614	10,063	11,248
Performance Shares Voluntarily Deferred into the Incentive Compensation Deferral Program	26,936	49,392	56,826
Performance Shares to be Settled (a)	717,308	733,442	752,706

(a) Performance shares settled for the three-year periods ended December 31, 2020 and 2019 settled in AEP common stock. Performance units settled for the three-year period ended December 31, 2018 settled in cash. In all cases, the settlement of common stock or cash occurs in the quarter following the end of the year shown.

The settlements were as follows:

Performance Shares and AEP Career Shares	Years Ended December 31, 2020	2019	2018
		(in millions)	
Cash Settlements for Performance Units	$ —	$ 58.3	$ 66.9
AEP Common Stock Settlements for Performance Shares	75.4	—	—
AEP Common Stock Settlements for Career Share Distributions	1.9	6.6	5.1

A summary of the status of AEP's nonvested Performance Shares as of December 31, 2020 and changes during the year ended December 31, 2020 were as follows:

Nonvested Performance Shares	Shares	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2020	1,113.4	$ 73.64
Awarded	424.8	116.56
Dividends	53.8	84.91
Vested (a)	(597.0)	66.45
Forfeited	(56.4)	87.58
Nonvested as of December 31, 2020	938.6	98.05

(a) The vested Performance Shares will be converted to 717 thousand shares based on the closing share price on the day before settlement.

Monte Carlo Valuation

AEP engages a third-party for a Monte Carlo valuation to calculate the fair value of the total shareholder return metric for the performance shares awarded during and after 2017. The valuations use a lattice model and the expected volatility assumptions used were the historical volatilities for AEP and the members of their peer group. The assumptions used in the Monte Carlo valuations were as follows:

	Years Ended December 31,		
Assumptions	2020	2019	2018
Valuation Period (in years) (a)	2.87	2.87	2.87
Expected Volatility Minimum	13.67 %	14.83 %	14.77 %
Expected Volatility Maximum	28.15 %	25.57 %	26.72 %
Expected Volatility Average	16.39 %	17.39 %	17.90 %
Dividend Rate (b)	— %	— %	— %
Risk Free Rate	1.40 %	2.49 %	2.34 %

(a) Period from award date to vesting date.
(b) Equivalent to reinvesting dividends.

Restricted Stock Units

The HR Committee grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. The RSUs accrue dividends as additional RSUs. The additional RSUs granted as dividends vest on the same date as the underlying RSUs. RSUs are converted into shares of AEP common stock upon vesting, except the RSUs granted prior to 2017 to AEP's executive officers which settled in cash. Executive officers are those officers who are subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934. For RSUs that settle in shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of RSUs granted by the grant date market closing price. For RSUs that settled in cash, compensation cost was recorded over the vesting period and adjusted for changes in fair value until vested. The fair value at vesting was determined by multiplying the number of RSUs vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is approximately 40 months from the grant date.

The HR Committee awarded RSUs, including additional units awarded as dividends, as follows:

Restricted Stock Units	Years Ended December 31, 2020	2019	2018
Awarded Units (in thousands)	268.7	304.8	260.0
Weighted-Average Grant Date Fair Value	$ 94.38	$ 81.57	$ 67.96

The total fair value and total intrinsic value of restricted stock units vested were as follows:

Restricted Stock Units	Years Ended December 31, 2020	2019	2018
		(in millions)	
Fair Value of Restricted Stock Units Vested	$ 22.9	$ 16.3	$ 16.6
Intrinsic Value of Restricted Stock Units Vested (a)	25.2	21.6	19.2

(a) Intrinsic value is calculated as market price at the vesting date.

A summary of the status of AEP's nonvested RSUs as of December 31, 2020 and changes during the year ended December 31, 2020 were as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2020	516.9	$ 75.55
Awarded	268.7	94.38
Vested	(307.6)	74.58
Forfeited	(30.0)	84.27
Nonvested as of December 31, 2020	448.0	86.56

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2020 was $37 million and the weighted-average remaining contractual life was 1.6 years.

Retirement Incentive and Severance Awards

In 2020 64,186 shares with a weighted-average grant date fair value of $83.74 were granted in connection with the voluntary retirement incentive program and other executive severance. The shares were fully vested on the grant date with a fair value of $5 million. See "Voluntary Retirement Incentive Program" section of Note 1 for additional information.

Other Stock-Based Plans

AEP also has a Stock Unit Accumulation Plan for Non-Employee Directors providing each non-employee director with AEP stock units as a substantial portion of the compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to non-employee directors are fully vested on their grant date. Stock units are settled in cash upon termination of board service or up to 10 years later if the participant so elects. Cash settlements for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date. After five years of service on the Board of Directors, non-employee directors receive subsequent AEP stock units as contributions to an AEP stock fund awarded under the Stock Unit Accumulation Plan. Such amounts may be exchanged into other market-based investments that are similar to the investment options available to employees that participate in AEP's Incentive Compensation Deferral Plan. These balances are also paid in cash upon termination of board service or up to 10 years later if the participant so elects.

Management records compensation cost for stock units when the units are awarded and adjusts the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

For the years ended December 31, 2020, 2019 and 2018, cash settlements for stock unit distributions were immaterial.

The Board of Directors awarded stock units, including units awarded for dividends, as follows:

	Years Ended December 31,		
Stock Unit Accumulation Plan for Non-Employee Directors	**2020**	**2019**	**2018**
Awarded Units (in thousands)	12.1	10.0	11.4
Weighted-Average Grant Date Fair Value	$ 83.80	$ 89.13	$ 70.41

Share-based Compensation Plans

For share-based payment arrangements the compensation cost, the actual tax benefit from the tax deductions for compensation cost recognized in income and the total compensation cost capitalized were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2020**	**2019**	**2018**
		(in millions)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 53.8	$ 57.9	$ 53.2
Actual Tax Benefit	7.2	8.4	7.7
Total Compensation Cost Capitalized	20.4	20.0	19.7

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

As of December 31, 2020, there was $78 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the 2015 LTIP. Unrecognized compensation cost related to unvested share-based arrangements will change as the fair value of performance shares is adjusted each period and as forfeitures for all award types are realized. AEP's unrecognized compensation cost will be recognized over a weighted-average period of 1.39 years.

Under the 2015 LTIP, AEP is permitted to use authorized but unissued shares, treasury shares, shares acquired in the open market specifically for distribution under these plans, or any combination thereof to fulfill share commitments. AEP's current practice is to use authorized but unissued shares to fulfill share commitments. The number of shares used to fulfill share commitments is generally reduced to offset tax withholding obligations.

16. RELATED PARTY TRANSACTIONS

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

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 12 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Power Coordination Agreement (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective Off-system Sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. With the transfer of OPCo's generation assets to AGR in 2014, AEPSC conducts only gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

System Integration Agreement (Applies to APCo, I&M, PSO and SWEPCo)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

The tables below represent revenues from affiliates, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2020							
Direct Sales to East Affiliates	$ —	$ —	$ 112.5	$ —	$ —	$ —	$ —
Auction Sales to OPCo (a)	—	—	5.3	3.1	—	—	—
Direct Sales to AEPEP	87.5	—	—	—	—	—	—
Transmission Revenues	—	885.0	49.1	2.9	16.6	—	37.4
Other Revenues	3.3	11.3	7.8	4.5	24.9	5.2	1.6
Total Affiliated Revenues	$ 90.8	$ 896.3	$ 174.7	$ 10.5	$ 41.5	$ 5.2	$ 39.0

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2019							
Direct Sales to East Affiliates	$ —	$ —	$ 128.6	$ —	$ —	$ —	$ —
Auction Sales to OPCo (a)	—	—	11.4	6.7	—	—	—
Direct Sales to AEPEP	157.2	—	—	—	—	—	(0.1)
Transmission Revenues	—	795.5	58.5	0.7	7.7	1.3	3.6
Other Revenues	3.3	11.2	6.8	3.1	19.6	4.8	1.4
Total Affiliated Revenues	$ 160.5	$ 806.7	$ 205.3	$ 10.5	$ 27.3	$ 6.1	$ 4.9

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2018							
Direct Sales to East Affiliates	$ —	$ —	$ 133.2	$ 0.1	$ —	$ —	$ —
Auction Sales to OPCo (a)	—	—	5.8	7.1	—	—	—
Direct Sales to AEPEP	103.6	—	—	—	—	—	—
Transmission Revenues	—	591.4	36.4	11.7	3.9	0.9	26.9
Other Revenues	1.6	7.5	6.0	3.2	17.1	4.5	1.5
Total Affiliated Revenues	$ 105.2	$ 598.9	$ 181.4	$ 22.1	$ 21.0	$ 5.4	$ 28.4

(a) Refer to the Ohio Auctions section below for further information regarding these amounts.

The tables below represent the purchased power expenses incurred for purchases from affiliates. AEP Texas, AEPTCo, APCo, PSO and SWEPCo did not purchase any power from affiliates for the years ended December 31, 2020, 2019 and 2018.

Related Party Purchases	**I&M**	**OPCo**
	(in millions)	
Year Ended December 31, 2020		
Auction Purchases from AEPEP (a)	$ —	$ 51.0
Auction Purchases from AEP Energy (a)	—	58.7
Auction Purchases from AEPSC (a)	—	10.0
Direct Purchases from AEGCo	172.8	—
Total Affiliated Purchases	$ 172.8	$ 119.7

Related Party Purchases	**I&M**	**OPCo**
	(in millions)	
Year Ended December 31, 2019		
Auction Purchases from AEPEP (a)	$ —	$ 64.6
Auction Purchases from AEP Energy (a)	—	69.9
Auction Purchases from AEPSC (a)	—	21.5
Direct Purchases from AEGCo	214.9	—
Total Affiliated Purchases	$ 214.9	$ 156.0

Related Party Purchases	**I&M**	**OPCo**
	(in millions)	
Year Ended December 31, 2018		
Auction Purchases from AEPEP (a)	$ —	$ 79.7
Auction Purchases from AEP Energy (a)	—	41.0
Auction Purchases from AEPSC (a)	—	14.6
Direct Purchases from AEGCo	237.9	—
Total Affiliated Purchases	$ 237.9	$ 135.3

(a) Refer to the Ohio Auctions section below for further information regarding this amount.

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates, respectively, on the Registrant Subsidiaries' statements of income. Since the Registrant Subsidiaries are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

PJM and SPP Transmission Service Charges (Applies to all Registrant Subsidiaries except AEP Texas)

The AEP East Companies are parties to the TA, which defines how transmission costs through the PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to AEP East Companies through the PJM OATT.

The following table shows the net transmission service charges recorded by APCo, I&M and OPCo:

	Years Ended December 31,		
Company	**2020**	**2019**	**2018**
		(in millions)	
APCo	$ 243.2	$ 222.3	$ 128.3
I&M	145.9	143.5	91.4
OPCo	417.4	373.4	210.1

The charges shown above are recorded in Other Operation expenses on the statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA in connection with the operation of the transmission assets of PSO and SWEPCo. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such a tariff.

Under the TCA, the parties to the agreement delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to PSO and SWEPCo through the SPP OATT.

The following table shows the net transmission service charges recorded by PSO and SWEPCo:

	Years Ended December 31,		
Company	**2020**	**2019**	**2018**
		(in millions)	
PSO	$ 69.7	$ 46.9	$ 65.9
SWEPCo	31.3	20.1	10.5

The charges shown above are recorded in Other Operation expenses on the statements of income.

AEPTCo provides transmission services to affiliates in accordance with the OATT, TA and TCA. AEPTCo recorded affiliated transmission revenues in Sales to AEP Affiliates on the statements of income. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

ERCOT Transmission Service Charges (Applies to AEP and AEP Texas)

Pursuant to an order from the PUCT, ETT bills AEP Texas for its ERCOT wholesale transmission services. ETT billed AEP Texas $28 million, $27 million and $27 million for transmission services in 2020, 2019 and 2018, respectively. The billings are recorded in Other Operation expenses on AEP Texas' statements of income.

Oklaunion PPA between AEP Texas and AEPEP (Applies to AEP Texas)

In 2007, AEP Texas entered into a PPA with an affiliate, AEPEP, whereby AEP Texas agreed to sell AEPEP 100% of AEP Texas' capacity and associated energy from its undivided interest (54.69%) in the Oklaunion Power Station. The PPA was approved by the FERC. In September 2018, the co-owners of Oklaunion Power Station voted to close the plant in 2020. Effective October 2018, AEP Texas increased depreciation expense to ensure the plant balances are fully depreciated as of September 2020 and recovered through the PPA billings to AEPEP. Under the early termination provisions of the PPA, AEPEP paid AEP Texas the full Property, Plant and Equipment balance through depreciation payments until termination of the PPA due to the plant closing in September 2020. See "Dispositions" section of Note 7 for additional information.

AEP Texas recorded revenue of $88 million, $157 million and $104 million from AEPEP for the years ended December 31, 2020, 2019 and 2018, respectively. These amounts are included in Sales to AEP Affiliates on AEP Texas' statements of income.

Joint License Agreement (Applies to AEPTCo, APCo, I&M, OPCo and PSO)

AEPTCo entered into a 50-year joint license agreement with APCo, I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. In addition, AEPTCo entered into a 5-year joint license agreement with APCo and WPCo. After the expiration of these agreements, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. AEPTCo recorded the following costs in Other Operation expense related to these agreements:

	Years Ended December 31,		
Billing Company	**2020**	**2019**	**2018**
		(in millions)	
APCo	$ 0.9	$ 0.2	$ —
I&M	3.0	1.5	2.2
KPCo	0.4	0.3	0.2
OPCo	4.5	2.2	2.9
PSO	0.4	0.3	0.3
WPCo	0.2	0.1	—

APCo, I&M, KPCo, OPCo, PSO and WPCo recorded income related to these agreements in Sales to AEP Affiliates on the statements of income.

Ohio Auctions (Applies to APCo, I&M and OPCo)

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy, AEPEP, APCo, KPCo, I&M and WPCo participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

Unit Power Agreements (Applies to I&M)

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. In November 2020, management announced that AEP will not renew the Rockport Plant, Unit 2 lease when it expires in December 2022. The I&M Power Agreement will continue in effect until the debt obligations of AEGCo secured by the Rockport Plant have been satisfied and discharged (currently expected to be December 2028).

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between AEGCo and KPCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. In November 2020, management announced that AEP will not renew the Rockport Plant, Unit 2 lease when it expires in December 2022. The KPCo UPA ends in December 2022.

Cook Coal Terminal (Applies to I&M, PSO and SWEPCo)

Cook Coal Terminal, which is owned by AEGCo, performs coal transloading and storage services at cost for I&M. The coal transloading costs were $12 million, $13 million and $12 million in 2020, 2019 and 2018, respectively. I&M recorded the cost of transloading services in Fuel on the balance sheets.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M, PSO and SWEPCo. The railcar maintenance costs were as follows:

Company	Years Ended December 31, 2020	2019	2018
		(in millions)	
I&M	$ 0.9	$ 1.3	$ 1.5
PSO	0.7	0.8	0.7
SWEPCo	3.0	4.0	3.4

I&M, PSO and SWEPCo recorded the cost of the railcar maintenance services in Fuel on the balance sheets.

I&M Barging, Urea Transloading and Other Services (Applies to APCo and I&M)

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

Company	Years Ended December 31, 2020	2019	2018
		(in millions)	
AEGCo	$ 10.6	$ 14.9	$ 19.9
APCo	43.7	38.9	35.1
KPCo	3.2	4.8	4.2
WPCo	3.3	4.8	4.2

Central Machine Shop (Applies to APCo, I&M, PSO and SWEPCo)

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. The AEP subsidiaries recorded these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the following affiliates:

Company	Years Ended December 31, 2020	2019	2018
		(in millions)	
AGR	$ 2.9	$ 0.8	$ 1.6
I&M	3.2	2.3	2.4
KPCo	0.9	1.4	1.7
PSO	0.9	1.1	0.5
SWEPCo	0.5	1.1	0.7

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following tables show the sales and purchases, recorded at net book value:

Sales

Company	Years Ended December 31, 2020	2019	2018
		(in millions)	
AEP Texas	$ 0.9	$ 0.9	$ 0.3
AEPTCo	0.2	—	—
APCo	5.7	5.5	5.4
I&M	1.5	7.5	8.2
OPCo	7.0	7.0	10.7
PSO	1.1	0.8	1.0
SWEPCo	0.8	0.2	0.8

Purchases

Company	Years Ended December 31, 2020	2019	2018
		(in millions)	
AEP Texas	$ 1.5	$ 0.3	$ 0.1
AEPTCo	6.0	10.2	18.5
APCo	1.3	6.0	0.6
I&M	3.4	0.9	2.0
OPCo	1.2	3.0	2.8
PSO	0.4	0.5	1.3
SWEPCo	2.8	0.7	0.8

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Sempra Renewables LLC PPAs (Applies to I&M, OPCo and SWEPCo)

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation. The operating wind generation portfolio includes seven wind farms. Prior to the acquisition, two wind farms had existing PPAs with I&M, OPCo and SWEPCo. One of the joint venture wind farms has PPAs with I&M and OPCo for a portion of its energy production. The I&M portion totaled $11 million and $9 million and the OPCo portion totaled $23 million and $17 million, respectively, for the years ended December 31, 2020 and 2019. Another joint venture wind farm has a PPA with SWEPCo for a portion of its energy production which totaled $14 million and $10 million, respectively, of purchased electricity for the years ended December 31, 2020 and 2019. See "Acquisitions" section of Note 7 for additional information.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. Charitable contributions to the AEP Foundation were recorded in Other Operation on the statements of income. In 2020, there were no charitable contributions made to the AEP Foundation. The charitable contributions to the AEP Foundation recorded in 2019 were as follows:

Company		Year Ended December 31, 2019
		(in millions)
AEP	$	50.0
AEP Texas		6.2
AEPTCo		6.5
APCo		8.9
I&M		9.0
OPCo		5.4
PSO		3.4
SWEPCo		5.5

OKTCo Radial Assets Transfer (Applies to AEP, AEPTCo and PSO)

In August 2020, AEPSC filed a request with FERC, on behalf of PSO and OKTCo, to transfer OKTCo's interests in its radial assets to PSO. See "FERC Rate Matters" section of Note 4 for additional information.

17. VARIABLE INTEREST ENTITIES AND EQUITY METHOD INVESTMENTS

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

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether AEP is the primary beneficiary of a VIE, management considers whether AEP has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently.

AEP holds ownership interests in businesses with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE, and if so, whether or not the VIE should be consolidated into AEP's financial statements. AEP has not provided material financial or other support that was not previously contractually required to any of its consolidated VIEs. If an entity is determined not to be a VIE, or if the entity is determined to be a VIE and AEP is not deemed to be the primary beneficiary, the entity is accounted for under the equity method of accounting.

Consolidated Variable Interests Entities (Applies to all Registrants except AEPTCo, OPCo and PSO)

Sabine

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2020, 2019 and 2018 were $131 million, $110 million and $152 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $155 million. Since SWEPCo uses self-bonding, the guarantee commits SWEPCo to complete the reclamation, in the event, Sabine does not complete the work. This guarantee ends upon completion of reclamation. The mine end-of-life has been adjusted to March 2023, in order to align with the announced closure of the Pirkey Power Plant. Reclamation is expected to be complete by 2037 at an estimated cost of $104 million. Actual reclamation costs could vary due to inflation and scope changes to the mine reclamation. SWEPCo recovers these costs through its fuel clauses. As of December 31, 2020, SWEPCo has recorded $89 million of mine reclamation costs in Asset Retirement Obligations and has collected $81 million through a rider for reclamation costs. The remaining $8 million is recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

DCC Fuel

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2020, 2019 and 2018 were $94 million, $95 million and $113 million, respectively. The leases were recorded as finance leases on I&M's balance sheets as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The finance leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

Transition Funding

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that AEP Texas is the primary beneficiary of Transition Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Transition Funding. As of December 31, 2020 and 2019, $66 million and $267 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $209 million and $274 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Transition Funding has securitized transition assets of $242 million and $389 million as of December 31, 2020 and 2019, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from AEP Texas under-recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Restoration Funding

Restoration Funding was formed for the sole purpose of issuing and servicing securitization bonds related to storm restoration of AEP Texas' distribution system primarily due to damage caused by Hurricane Harvey. Management has concluded that AEP Texas is the primary beneficiary of Restoration Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Restoration Funding. As of December 2020 and 2019, $23 million and $14 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $195 million and $221 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Restoration Funding has securitized assets of $205 million and $232 million as of December 31, 2020 and 2019, respectively, which are presented separately on the face of the balance sheets. The securitized restoration assets represent the right to impose and collect Texas storm restoration costs from customers receiving electric transmission or distribution service from AEP Texas under-recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Restoration Funding's securitized assets and remits all related amounts collected from customers to Restoration Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Restoration Funding's assets and liabilities on the balance sheets.

Appalachian Consumer Rate Relief Funding

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. As of December 31, 2020 and 2019, $25 million and $25 million of the securitized bonds were included in Long-term Debt Due Within One Year - Nonaffiliated, respectively, and $199 million and $223 million were included in Long-term Debt - Nonaffiliated, respectively, on the balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $210 million and $235 million as of December 31, 2020 and 2019, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's balance sheets.

AEP Credit

AEP Credit is a wholly-owned subsidiary of Parent. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 25% of AEP Credit's short-term borrowing needs in excess of third-party financings. Any third-party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on AEP's control of AEP Credit, management concluded that AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables - AEP Credit" section of Note 14.

EIS

AEP's subsidiaries participate in one protected cell of EIS for six lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third-parties access to this insurance. AEP's subsidiaries and any allowed third-parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the years ended December 31, 2020, 2019 and 2018 was $31 million, $34 million and $34 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

Transource Energy

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. Transource Energy's activities consist of the development, construction and operation of FERC-regulated transmission assets in Missouri, West Virginia, Pennsylvania, Maryland and Oklahoma. Transource Energy has a credit facility agreement where borrowings are loaned through intercompany lending agreements to its subsidiaries. The creditor to the agreement has no recourse to the general credit of AEP. Transource Energy's credit facility agreement contains certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. See the tables below for the classification of Transource Energy's assets and liabilities on the balance sheets.

Desert Sky Wind Farm LLC and Trent Wind Farm LLC

Desert Sky Wind Farm LLC and Trent Wind Farm LLC (collectively the LLCs) were established for the purpose of repowering, owning and operating wind-powered electric energy generation facilities in Texas. In January 2018, AEP admitted a nonaffiliate as a member of the LLCs to own and repower Desert Sky and Trent. The nonaffiliate contributed full turbine sets to each project in exchange for a 20.1% interest in the LLCs. The nonaffiliates' contribution of $84 million was recorded as Net Property, Plant and Equipment on the balance sheets, which was the fair value as of the contribution date determined based on key input assumptions of the original cost of the full turbine sets and the discounted cash flow benefit associated with the production tax credits available from repowering Desert Sky and Trent based on their expected net capacity, capacity factor and the operational availability. From January 2018 through July 2020, AEP owned 79.9% of the LLCs. As a result, management concluded that the LLCs were VIEs and that AEP was the primary beneficiary based on its power to direct the activities that most significantly impact their economic performance. Also in January 2018, the LLCs entered into a forward PPA for the sale of power to AEPEP related to deliveries of electricity beginning January 1, 2021 for a 12 year period. Prior to the effective date of the PPA, the LLCs sold power at market rates into ERCOT. AEP and the nonaffiliate shared tax attributes including PTC and cash distributions from the operation of the LLCs generally consistent with the ownership percentages. See the tables below for the classification of the LLCs' assets and liabilities on the balance sheets.

In August 2020, AEP exercised its call right which required the nonaffiliate to sell its noncontrolling interest in the LLCs to AEP. The nonaffiliates' interest in the LLCs was presented as Redeemable Noncontrolling Interest on the balance sheets. 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. As of December 31, 2020 and 2019, AEP recorded $0 and $66 million, respectively, of Redeemable Noncontrolling Interest in Mezzanine Equity on the balance sheets.

Apple Blossom Wind Holdings LLC and Black Oak Getty Wind Holdings LLC

In April 2019, AEP acquired an equity interest in Apple Blossom Wind Holdings LLC (Apple Blossom) and Black Oak Getty Wind Holdings LLC (Black Oak) (collectively the Project Entities) as part of the purchase of Sempra Renewables LLC. Both of the Project Entities have long-term PPAs for 100% of their energy production. The Project Entities are tax equity partnerships with nonaffiliated noncontrolling interests to which a percentage of earnings, tax attributes and cash flows are allocated in accordance with the respective limited liability company agreements. Management has concluded that the Project Entities are VIEs and that AEP is the primary beneficiary based on its power as managing member to direct the activities that most significantly impact the Project Entities' economic performance. In addition, AEP has not provided material financial or other support to the Project Entities that was not previously contractually required. As the primary beneficiary of the Project Entities, AEP consolidates the Project Entities into its financial statements. See the table below for the classification of Project Entities' assets and liabilities on the balance sheets.

The nonaffiliated interests in the Project Entities is presented in Noncontrolling Interests on the balance sheets. As of December 31, 2020 and 2019, AEP recorded $119 million and $128 million, respectively, of Noncontrolling Interests related to the Project Entities in Equity on the balance sheets.

The Project Entities' tax equity partnerships represent substantive profit-sharing arrangements. The method for attributing income and loss to the noncontrolling interests is a balance sheet approach referred to as the hypothetical liquidation at book value (HLBV) method. Under the HLBV method, the income and loss attributable to the noncontrolling interests reflect changes in the amounts the members would hypothetically receive at each balance sheet date under the liquidation provisions of the respective limited liability company agreements, assuming the net assets of these entities were liquidated at recorded amounts, after taking into account any capital transactions, such as contributions or distributions, between the entities and the members. For the years ended December 31, 2020 and 2019, the HLBV method resulted in a loss of $6 million and $6 million, respectively, allocated to Noncontrolling Interests.

Santa Rita East

In July 2019, AEP acquired a 75% interest in Santa Rita East Wind Energy Holdings, LLC and its wholly-owned subsidiary, Santa Rita East Wind Energy, LLC (collectively, Santa Rita East). In November 2020, AEP acquired an additional 10% interest in Santa Rita East resulting in AEP having a total interest of 85%. Santa Rita East is a partnership whose sole purpose is to own and operate a 302 MW wind generation facility in west Texas. Santa Rita East delivers energy and provides renewable energy credits through three long-term PPAs totaling 260 MWs. The remaining 42 MWs of energy are sold at wholesale into ERCOT. Management has concluded that Santa Rita East is a VIE and that AEP is the primary beneficiary based on its power as managing member of the partnership to direct the activities that most significantly impact Santa Rita East's economic performance. As the primary beneficiary of Santa Rita East, AEP consolidates Santa Rita East into its financial statements. See the table below for the classification of Santa Rita East's assets and liabilities on the balance sheets.

AEP recognized $23 million and $10 million of PTC attributable to Santa Rita East for the years ended December 31, 2020 and 2019, respectively, which was recorded in Income Tax Expense (Benefit) on the statements of income. The nonaffiliated interest in Santa Rita East is presented in Noncontrolling Interests on the balance sheets. As of December 31, 2020 and 2019, AEP recorded $61 million and $118 million, respectively, of Noncontrolling Interests related to Santa Rita East in Equity on the balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2020

	Registrant Subsidiaries				
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Transition Funding**	**AEP Texas Restoration Funding**	**APCo Appalachian Consumer Rate Relief Funding**
			(in millions)		
ASSETS					
Current Assets	$ 88.0	$ 76.1	$ 61.2	$ 23.3	$ 16.8
Net Property, Plant and Equipment	97.3	138.9	—	—	—
Other Noncurrent Assets	99.3	70.9	273.9 (a)	214.9 (b)	212.7 (c)
Total Assets	$ 284.6	$ 285.9	$ 335.1	$ 238.2	$ 229.5
LIABILITIES AND EQUITY					
Current Liabilities	$ 57.7	$ 76.0	$ 69.8	$ 33.9	$ 28.7
Noncurrent Liabilities	225.3	209.9	246.5	203.1	198.9
Equity	1.6	—	18.8	1.2	1.9
Total Liabilities and Equity	$ 284.6	$ 285.9	$ 335.1	$ 238.2	$ 229.5

(a) Includes an intercompany item eliminated in consolidation of $32 million.
(b) Includes an intercompany item eliminated in consolidation of $9 million.
(c) Includes an intercompany item eliminated in consolidation of $3 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2020

	Other Consolidated VIEs				
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**	**Apple Blossom and Black Oak**	**Santa Rita East**
			(in millions)		
ASSETS					
Current Assets	$ 960.4	$ 198.1	$ 22.2	$ 9.6	$ 6.0
Net Property, Plant and Equipment	—	—	458.7	223.1	453.1
Other Noncurrent Assets	12.9	—	3.7	12.1	—
Total Assets	$ 973.3	$ 198.1	$ 484.6	$ 244.8	$ 459.1
LIABILITIES AND EQUITY					
Current Liabilities	$ 827.2	$ 43.1	$ 32.6	$ 5.3	$ 3.5
Noncurrent Liabilities	0.8	62.5	185.0	4.9	6.7
Equity	145.3	92.5	267.0	234.6	448.9
Total Liabilities and Equity	$ 973.3	$ 198.1	$ 484.6	$ 244.8	$ 459.1

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2019

	Registrant Subsidiaries				
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Transition Funding**	**AEP Texas Restoration Funding**	**APCo Appalachian Consumer Rate Relief Funding**
			(in millions)		
ASSETS					
Current Assets	$ 80.0	$ 86.5	$ 187.0	$ 9.4	$ 21.5
Net Property, Plant and Equipment	111.6	156.8	—	—	—
Other Noncurrent Assets	93.2	82.5	428.1 (a)	234.4 (b)	237.5 (c)
Total Assets	$ 284.8	$ 325.8	$ 615.1	$ 243.8	$ 259.0
LIABILITIES AND EQUITY					
Current Liabilities	$ 50.6	$ 86.4	$ 280.2	$ 16.3	$ 28.3
Noncurrent Liabilities	233.6	239.4	316.3	226.3	228.8
Equity	0.6	—	18.6	1.2	1.9
Total Liabilities and Equity	$ 284.8	$ 325.8	$ 615.1	$ 243.8	$ 259.0

(a) Includes an intercompany item eliminated in consolidation of $39 million.
(b) Includes an intercompany item eliminated in consolidation of $1 million.
(c) Includes an intercompany item eliminated in consolidation of $3 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2019

	Other Consolidated VIEs					
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**	**Desert Sky and Trent**	**Apple Blossom and Black Oak**	**Santa Rita East**
			(in millions)			
ASSETS						
Current Assets	$ 842.8	$ 194.6	$ 25.8	$ 7.8	$ 10.1	$ 17.7
Net Property, Plant and Equipment	—	—	424.1	330.6	231.4	465.2
Other Noncurrent Assets	7.1	—	3.2	10.1	13.1	0.3
Total Assets	$ 849.9	$ 194.6	$ 453.1	$ 348.5	$ 254.6	$ 483.2
LIABILITIES AND EQUITY						
Current Liabilities	$ 805.2	$ 40.7	$ 192.4	$ 5.5	$ 5.4	$ 3.9
Noncurrent Liabilities	0.9	78.0	4.8	15.8	4.7	7.5
Equity	43.8	75.9	255.9	327.2	244.5	471.8
Total Liabilities and Equity	$ 849.9	$ 194.6	$ 453.1	$ 348.5	$ 254.6	$ 483.2

Non-Consolidated Significant Variable Interests

DHLC

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. The operations of DHLC are governed by the lignite mining agreement among SWEPCo, CLECO and DHLC. SWEPCo and CLECO share the executive board seats and voting rights equally. In accordance with the lignite mining agreement, each entity is responsible for 50% of DHLC's obligations, including debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2020, 2019 and 2018 were $142 million, $55 million and $58 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets. SWEPCo's investment in DHLC was:

	December 31,			
	2020		2019	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 7.6	$ 7.6	$ 7.6	$ 7.6
Retained Earnings	20.4	20.4	17.5	17.5
SWEPCo's Share of Obligations	—	98.5	—	130.0
Total Investment in DHLC	$ 28.0	$ 126.5	$ 25.1	$ 155.1

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2020, AEP's ownership in OVEC was 43.47%. Parent owns 39.17% and OPCo owns 4.3%. APCo, I&M and OPCo are members to an intercompany power agreement. The Registrants' power participation ratios are 15.69% for APCo, 7.85% for I&M and 19.93% for OPCo. Participants of this agreement are entitled to receive and are obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2020 and 2019, OVEC's outstanding indebtedness was approximately $1.3 billion and $1.4 billion, respectively. Although they are not an obligor or guarantor, the Registrants' are responsible for their respective ratio of OVEC's outstanding debt through the intercompany power agreement. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6 for additional information.

AEP is not required to consolidate OVEC as it is not the primary beneficiary, although AEP and its subsidiary holds a significant variable interest in OVEC. Power to control decision making that significantly impacts the economic performance of OVEC is shared amongst the owners through their representation on the Board of Directors of OVEC and the representation of the sponsoring companies on the Operating Committee under the intercompany power agreement.

AEP's investment in OVEC was:

	December 31, 2020		December 31, 2019	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 4.4	$ 4.4	$ 4.4	$ 4.4
AEP's Ratio of OVEC Debt (a)	—	555.0	—	588.9
Total Investment in OVEC	$ 4.4	$ 559.4	$ 4.4	$ 593.3

(a) Based on the Registrants' power participation ratios APCo, I&M and OPCo's share of OVEC debt was $200 million, $100 million and $255 million as of December 31, 2020 and $213 million, $106 million and $270 million as of December 31, 2019, respectively.

Power purchased by the Registrant Subsidiaries from OVEC is included in Purchased Electricity for Resale on the statements of income and is shown in the table below:

Company	Years Ended December 31, 2020	2019	2018
	(in millions)		
APCo	$ 94.4	$ 104.5	$ 100.4
I&M	47.2	52.3	50.2
OPCo	120.8	132.7	127.5

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct-charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

Company	Years Ended December 31, 2020	2019	2018
	(in millions)		
AEP Texas	$ 199.4	$ 206.6	$ 184.3
AEPTCo	270.3	242.3	220.4
APCo	294.9	308.3	295.6
I&M	210.2	184.8	173.5
OPCo	232.8	230.4	214.9
PSO	113.2	125.7	121.5
SWEPCo	161.8	169.5	164.4

The carrying amount and classification of variable interest in AEPSC's accounts payable were as follows:

	December 31, 2020		2019	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
AEP Texas	$ 30.5	$ 30.5	$ 32.4	$ 32.4
AEPTCo	45.9	45.9	33.4	33.4
APCo	42.8	42.8	44.1	44.1
I&M	27.1	27.1	28.6	28.6
OPCo	33.9	33.9	33.2	33.2
PSO	15.7	15.7	18.1	18.1
SWEPCo	22.0	22.0	23.4	23.4

AEGCo

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. Total billings to I&M from AEGCo for the years ended December 31, 2020, 2019 and 2018 were $173 million, $215 million and $238 million, respectively. The carrying amounts of I&M's liabilities associated with AEGCo as of December 31, 2020 and 2019 were $9 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability. See "Rockport Lease" section of Note 13 for additional information.

Significant Equity Method Investments in Unconsolidated Entities

For a discussion of the equity method of accounting, see the "Equity Investment in Unconsolidated Entities" section of Note 1.

Sempra Renewables LLC

In April 2019, AEP acquired a 50% interest in five wind farms in multiple states as part of the purchase of Sempra Renewables LLC. The wind farms are joint ventures with BP Wind Energy who holds the other 50% interest. All five wind farms have long-term PPAs for 100% of their energy production. One of the jointly-owned wind farms has PPAs with I&M and OPCo for a portion of its energy production. Another jointly-owned wind farm has a PPA with SWEPCo for a portion of its energy production. The joint venture wind farms are not considered VIEs and AEP is not required to consolidate them as AEP does not have a controlling financial interest. However, AEP is able to exercise significant influence over the wind farms and therefore applies the equity method of accounting. As of December 31, 2020 and 2019, AEP's investment in the five joint venture wind farms was $376 million and $394 million, respectively. The investment includes amounts recognized in AOCI related to interest rate cash flow hedges. The investment is comprised of a historical investment of $399 million plus a basis difference of $(12) million. AEP's equity earnings associated with the five joint venture wind farms was $2 million and a loss of $4 million for the years ended December 31, 2020 and 2019, respectively. AEP recognized $36 million and $27 million of PTC attributable to the joint venture wind farms for the years ended December 31, 2020 and 2019, respectively, which was recorded in Income Tax Expense (Benefit) on the statements of income.

ETT

ETT designs, acquires, constructs, owns and operates certain transmission facilities in ERCOT. Berkshire Hathaway Energy, a nonaffiliated entity, holds a 50% membership interest in ETT and AEP Transmission Holdco holds a 50% membership interest in ETT. As a result, AEP, through its wholly-owned subsidiary, holds a 50% membership interest in ETT. As of December 31, 2020 and 2019, AEP's investment in ETT was $732 million and $695 million, respectively. AEP's equity earnings associated with ETT were $68 million, $66 million and $62 million for the years ended December 31, 2020, 2019 and 2018 respectively.

18. PROPERTY, PLANT AND EQUIPMENT

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

Property, Plant and Equipment is shown functionally on the face of the balance sheets. The following tables include the total plant balances as of December 31, 2020 and 2019:

December 31, 2020	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 21,587.8	(a)	$ —	$ —	$ 6,633.7	$ 5,264.7	$ —	$ 1,480.7	$ 4,681.4	(a)
Transmission	27,841.5		5,279.6	9,593.5	3,900.5	1,696.4	2,831.9	1,069.9	2,165.7	
Distribution	23,972.1		4,580.8	—	4,464.3	2,594.6	5,708.3	2,853.0	2,382.5	
Other	4,852.4		866.0	328.8	598.0	644.6	888.5	388.1	564.5	
CWIP	3,815.0	(a)	614.1	1,422.6	484.6	362.4	362.3	128.7	228.3	(a)
Less: Accumulated Depreciation	20,094.2		1,528.1	572.8	4,711.0	3,538.6	2,348.8	1,607.3	3,032.0	
Total Regulated Property, Plant and Equipment - Net	61,974.6		9,812.4	10,772.1	11,370.1	7,024.1	7,442.2	4,313.1	6,990.4	
Nonregulated Property, Plant and Equipment - Net	1,927.0		1.2	0.7	24.0	28.2	9.9	6.9	97.8	
Total Property, Plant and Equipment - Net	$ 63,901.6		$ 9,813.6	$ 10,772.8	$ 11,394.1	$ 7,052.3	$ 7,452.1	$ 4,320.0	$ 7,088.2	

December 31, 2019	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 21,323.5	(a)	$ —	$ —	$ 6,563.7	$ 5,099.7	$ —	$ 1,574.6	$ 4,691.4	(a)
Transmission	24,763.4		4,466.5	8,137.9	3,584.1	1,641.8	2,686.3	948.5	2,056.5	
Distribution	22,440.8		4,215.2	—	4,201.7	2,437.6	5,323.5	2,684.8	2,270.7	
Other	4,369.6		803.4	268.2	542.0	590.9	754.7	337.2	520.6	
CWIP	4,261.2	(a)	763.9	1,485.7	593.4	382.3	394.4	133.4	210.1	(a)
Less: Accumulated Depreciation	18,778.1		1,465.0	402.3	4,425.6	3,281.4	2,261.7	1,579.9	2,766.2	
Total Regulated Property, Plant and Equipment - Net	58,380.4		8,784.0	9,489.5	11,059.3	6,870.9	6,897.2	4,098.6	6,983.1	
Nonregulated Property, Plant and Equipment - Net	1,757.7		61.1	1.4	22.6	28.8	9.8	4.7	112.1	
Total Property, Plant and Equipment - Net	$ 60,138.1		$ 8,845.1	$ 9,490.9	$ 11,081.9	$ 6,899.7	$ 6,907.0	$ 4,103.3	$ 7,095.2	

(a) AEP and SWEPCo's regulated generation and regulated CWIP include amounts related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

Depreciation, Depletion and Amortization

The Registrants provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide total regulated annual composite depreciation rates and depreciable lives for the Registrants:

AEP

	2020		2019		2018	
Functional Class of Property	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate Ranges**	**Depreciable Life Ranges (in years)**
Generation	2.7% - 6.3%	20 - 132	2.5% - 5.5%	20 - 132	2.4% - 4.0%	20 - 132
Transmission	2.0% - 2.6%	15 - 75	1.8% - 2.6%	15 - 81	1.6% - 2.7%	15 - 81
Distribution	2.7% - 3.7%	7 - 78	2.7% - 3.7%	7 - 78	2.7% - 3.6%	7 - 78
Other	2.8% - 11.3%	5 - 75	2.6% - 9.5%	5 - 75	2.3% - 9.8%	5 - 75

AEP Texas

	2020		2019		2018	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Transmission	2.0%	50 - 75	1.8%	45 - 81	1.7%	45 - 81
Distribution	3.1%	7 - 70	3.5%	7 - 70	3.6%	7 - 70
Other	6.1%	5 - 50	6.3%	5 - 50	6.0%	5 - 50

AEPTCo

	2020		2019		2018	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Transmission	2.4%	24 - 75	2.0%	24 - 75	1.9%	20 - 75
Other	6.3%	5 - 64	5.8%	5 - 64	5.6%	5 - 64

APCo

	2020		2019		2018	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Generation	3.3%	35 - 118	3.2%	35 - 118	3.1%	35 - 112
Transmission	2.2%	15 - 75	1.8%	15 - 71	1.6%	15 - 68
Distribution	3.7%	12 - 57	3.7%	12 - 57	3.6%	10 - 57
Other	7.8%	5 - 55	7.2%	5 - 55	7.4%	5 - 55

I&M

	2020		2019		2018	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Generation	4.6%	20 - 132	4.0%	20 - 132	3.4%	20 - 132
Transmission	2.3%	45 - 70	1.9%	50 - 73	1.8%	50 - 73
Distribution	3.4%	14 - 71	3.4%	9 - 75	3.1%	9 - 75
Other	10.2%	5 - 51	9.4%	5 - 50	8.9%	5 - 50

OPCo

	2020		2019		2018	
Functional Class of Property	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**	**Annual Composite Depreciation Rate**	**Depreciable Life Ranges (in years)**
Transmission	2.3%	39 - 60	2.3%	39 - 60	2.3%	39 - 60
Distribution	3.1%	14 - 65	3.1%	14 - 65	3.0%	14 - 65
Other	5.0%	5 - 50	4.9%	5 - 50	6.3%	5 - 50

PSO

Functional Class of Property	2020 Annual Composite Depreciation Rate	2020 Depreciable Life Ranges (in years)	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)
Generation	3.1%	35 - 75	2.9%	35 - 75	2.9%	35 - 75
Transmission	2.2%	45 - 75	2.4%	45 - 75	2.3%	45 - 75
Distribution	2.9%	15 - 78	2.9%	15 - 78	2.9%	15 - 78
Other	5.7%	5 - 64	5.6%	5 - 64	6.3%	5 - 64

SWEPCo

Functional Class of Property	2020 Annual Composite Depreciation Rate	2020 Depreciable Life Ranges (in years)	2019 Annual Composite Depreciation Rate	2019 Depreciable Life Ranges (in years)	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)
Generation	2.7%	35 - 65	2.5%	40 - 70	2.4%	40 - 70
Transmission	2.3%	47 - 73	2.4%	50 - 73	2.2%	50 - 73
Distribution	2.7%	15 - 67	2.7%	25 - 70	2.7%	25 - 70
Other	8.5%	5 - 52	7.6%	5 - 55	8.0%	5 - 55

The following table includes the nonregulated annual composite depreciation rate ranges and nonregulated depreciable life ranges for AEP. Depreciation rate ranges and depreciable life ranges are not meaningful for nonregulated property of AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo for 2020, 2019 and 2018.

Functional Class of Property	2020 Annual Composite Depreciation Rate Ranges	2020 Depreciable Life Ranges (in years)		2019 Annual Composite Depreciation Rate Ranges	2019 Depreciable Life Ranges (in years)		2018 Annual Composite Depreciation Rate Ranges	2018 Depreciable Life Ranges (in years)	
Generation	3.6% - 4.0%	15 - 59		3.2% - 21.2%	15 - 59		3.4% - 22.3%	15 - 59	
Transmission	2.5%	30 - 40		2.5%	30 - 40		2.4%	40	
Distribution	NA	NA		2.3%	40		2.3%	40	
Other	16.1%	5 - 50	(a)	17.6%	5 - 50	(a)	16.3%	5 - 50	(a)

(a) SWEPCo's nonregulated property, plant and equipment is depreciated using the straight-line method over a range of 3 to 20 years.
NA Not applicable.

SWEPCo provides for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. SWEPCo uses either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. SWEPCo includes these costs in fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (Applies to all Registrants except AEPTCo)

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms, solar farms and certain coal-mining facilities. I&M records ARO for the decommissioning of the Cook Plant. The Registrants have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrants plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrants abandon or cease the use of specific easements, which is not expected.

The Registrants recorded the following revisions to ARO estimates as of December 31, 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 5 - Effects of Regulation for additional information. In September 2020, SWEPCo recorded an $18 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 5 - Effects of Regulation for additional information.
- 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 7 - Acquisitions and Dispositions for additional information.
- In June 2020, APCo recorded a revision to increase estimated Glen Lyn Station ash disposal ARO liabilities by $199 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 6 - Commitments, Guarantees and Contingencies for additional information.

As of December 31, 2020 and 2019, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.80 billion and $1.73 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2020 and 2019, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $2.98 billion and $2.65 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2020 and 2019 aggregate carrying amounts of ARO by Registrant:

Company	**ARO as of December 31, 2019**	**Accretion Expense**	**Liabilities Incurred**	**Liabilities Settled**	**Revisions in Cash Flow Estimates (a)**	**ARO as of December 31, 2020**
			(in millions)			
AEP (b)(c)(d)(e)	$ 2,418.9	$ 102.4	$ 0.3	$ (188.0)	$ 183.1	$ 2,516.7
AEP Texas (b)(e)	29.1	0.8	—	(8.5)	(16.8)	4.6
APCo (b)(e)	111.1	8.9	—	(7.8)	200.9	313.1
I&M (b)(c)(e)	1,748.6	70.2	0.1	(0.2)	(4.9)	1,813.8
OPCo (e)	1.8	0.1	—	—	—	1.9
PSO (b)(e)	52.2	3.1	—	(3.1)	(4.8)	47.4
SWEPCo (b)(d)(e)	212.2	10.7	—	(10.9)	10.1	222.1

Company	**ARO as of December 31, 2018**	**Accretion Expense**	**Liabilities Incurred**	**Liabilities Settled**	**Revisions in Cash Flow Estimates (a)**	**ARO as of December 31, 2019**
			(in millions)			
AEP (b)(c)(d)(e)	$ 2,355.5	$ 102.5	$ 12.0	$ (118.1)	$ 67.0	$ 2,418.9
AEP Texas (b)(e)	27.9	1.3	—	(0.2)	0.1	29.1
APCo (b)(e)	116.1	5.9	—	(17.6)	6.7	111.1
I&M (b)(c)(e)	1,681.3	67.4	—	(0.2)	0.1	1,748.6
OPCo (e)	1.8	0.1	—	(0.3)	0.2	1.8
PSO (b)(e)	46.9	3.1	—	(0.4)	2.6	52.2
SWEPCo (b)(d)(e)	206.8	10.3	—	(11.8)	6.9	212.2

(a) Unless discussed above, primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.80 billion and $1.73 billion as of December 31, 2020 and 2019, respectively.
(d) Includes ARO related to Sabine and DHLC.

(e) Includes ARO related to asbestos removal.

Allowance for Funds Used During Construction and Interest Capitalization

The Registrants' amounts of Allowance for Equity Funds Used During Construction are summarized in the following table:

Company	Years Ended December 31, 2020	2019	2018
		(in millions)	
AEP	$ 148.1	$ 168.4	$ 132.5
AEP Texas	19.4	15.2	20.0
AEPTCo	74.0	84.3	70.6
APCo	14.6	16.6	13.2
I&M	11.5	19.4	11.9
OPCo	12.5	18.2	9.8
PSO	4.0	2.7	0.4
SWEPCo	7.7	6.8	6.0

The Registrants' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

Company	Years Ended December 31, 2020	2019	2018
		(in millions)	
AEP	$ 66.0	$ 88.7	$ 73.6
AEP Texas	12.5	20.0	18.4
AEPTCo	25.5	32.2	26.1
APCo	7.9	9.3	8.4
I&M	5.7	8.9	7.4
OPCo	6.2	6.7	5.8
PSO	2.0	1.9	0.9
SWEPCo	3.9	4.0	4.8

Jointly-owned Electric Facilities (Applies to AEP, AEP Texas, I&M, PSO and SWEPCo)

The Registrants have electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. Each Registrant's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

			Registrant's Share as of December 31, 2020		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Dolet Hills Power Station, Unit 1 (a)	Lignite	40.2 %	$ 342.4	$ 4.6	$ 295.4
Flint Creek Generating Station, Unit 1 (b)	Coal	50.0 %	377.2	3.0	116.0
Pirkey Power Plant, Unit 1 (b)	Lignite	85.9 %	602.8	3.7	441.0
Oklaunion Power Station (f)(g)	Coal	70.3 %	—	—	—
Turk Generating Plant (b)	Coal	73.3 %	1,594.3	2.8	257.3
Total			$ 2,916.7	$ 14.1	$ 1,109.7
AEP Texas					
Oklaunion Power Station (f)(g)	Coal	54.7 %	$ —	$ —	$ —
I&M					
Rockport Generating Plant (c)(d)(e)	Coal	50.0 %	$ 1,228.5	$ 19.6	$ 677.3
PSO					
Oklaunion Power Station (f)(g)	Coal	15.6 %	$ —	$ —	$ —
SWEPCo					
Dolet Hills Power Station, Unit 1 (a)	Lignite	40.2 %	$ 342.4	$ 4.6	$ 295.4
Flint Creek Generating Station, Unit 1 (b)	Coal	50.0 %	377.2	3.0	116.0
Pirkey Power Plant, Unit 1 (b)	Lignite	85.9 %	602.8	3.7	441.0
Turk Generating Plant (b)	Coal	73.3 %	1,594.3	2.8	257.3
Total			$ 2,916.7	$ 14.1	$ 1,109.7

	Fuel Type	Percent of Ownership	Registrant's Share as of December 31, 2019 Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Dolet Hills Power Station, Unit 1 (a)	Lignite	40.2 %	$ 337.3	$ 6.2	$ 216.5
Flint Creek Generating Station, Unit 1 (b)	Coal	50.0 %	374.3	3.4	101.1
Pirkey Power Plant, Unit 1 (b)	Lignite	85.9 %	607.8	7.7	416.8
Oklaunion Power Station (f)(g)	Coal	70.3 %	106.6	0.1	91.7
Turk Generating Plant (b)	Coal	73.3 %	1,593.3	1.7	225.8
Total			$ 3,019.3	$ 19.1	$ 1,051.9
AEP Texas					
Oklaunion Power Station (f)(g)	Coal	54.7 %	$ 351.7	$ —	$ 291.9
I&M					
Rockport Generating Plant (c)(d)(e)	Coal	50.0 %	$ 1,114.2	$ 105.5	$ 586.2
PSO					
Oklaunion Power Station (f)(g)	Coal	15.6 %	$ 106.6	$ 0.1	$ 91.7
SWEPCo					
Dolet Hills Power Station, Unit 1 (a)	Lignite	40.2 %	$ 337.3	$ 6.2	$ 216.5
Flint Creek Generating Station, Unit 1 (b)	Coal	50.0 %	374.3	3.4	101.1
Pirkey Power Plant, Unit 1 (b)	Lignite	85.9 %	607.8	7.7	416.8
Turk Generating Plant (b)	Coal	73.3 %	1,593.3	1.7	225.8
Total			$ 2,912.7	$ 19.0	$ 960.2

(a) Operated by CLECO, a nonaffiliated company.
(b) Operated by SWEPCo.
(c) Operated by I&M.
(d) Amounts include I&M's 50% ownership of both Unit 1 and capital additions for Unit 2. Unit 2 is subject to an operating lease with a nonaffiliated company. See the "Rockport Lease" section of Note 13 for additional information.
(e) AEGCo owns 50% of Unit 1 with I&M and 50% of capital additions for Unit 2.
(f) Operated by PSO, which owned 15.6%. Also was jointly-owned (54.7%) by AEP Texas and various nonaffiliated companies.
(g) Oklaunion Power Station was retired in September 2020 and sold to a nonaffiliated third-party in October 2020. See the "Dispositions" section of Note 7 for additional information.

19. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The table below represents AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Year Ended December 31, 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	$ 3,606.8	$ 2,086.9	$ —	$ —	$ —	$ —	$ 5,693.7
Commercial Revenues	2,016.2	1,048.6	—	—	—	—	3,064.8
Industrial Revenues	2,018.0	390.1	—	—	—	(0.7)	2,407.4
Other Retail Revenues	155.6	42.5	—	—	—	—	198.1
Total Retail Revenues	7,796.6	3,568.1	—	—	—	(0.7)	11,364.0
Wholesale and Competitive Retail Revenues:							
Generation Revenues	588.3	—	—	131.9	—	—	720.2
Transmission Revenues (a)	334.5	467.0	1,257.0	—	—	(1,006.7)	1,051.8
Renewable Generation Revenues (b)	—	—	—	60.9	—	(1.6)	59.3
Retail, Trading and Marketing Revenues (c)	—	—	—	1,486.9	(5.5)	(103.0)	1,378.4
Total Wholesale and Competitive Retail Revenues	922.8	467.0	1,257.0	1,679.7	(5.5)	(1,111.3)	3,209.7
Other Revenues from Contracts with Customers (b)	163.2	157.8	22.4	2.3	92.5	(148.6)	289.6
Total Revenues from Contracts with Customers	8,882.6	4,192.9	1,279.4	1,682.0	87.0	(1,260.6)	14,863.3
Other Revenues:							
Alternative Revenues (b)	(3.2)	70.0	(80.6)	—	—	7.5	(6.3)
Other Revenues (b)	—	83.0	—	43.6	9.8	(74.9)	61.5
Total Other Revenues	(3.2)	153.0	(80.6)	43.6	9.8	(67.4)	55.2
Total Revenues	$ 8,879.4	$ 4,345.9	$ 1,198.8	$ 1,725.6	$ 96.8	$ (1,328.0)	$ 14,918.5

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $965 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 $103 million. The remaining affiliated amounts were immaterial.

	Year Ended December 31, 2019						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 3,643.7	$ 2,069.9	$ —	$ —	$ —	$ —	$ 5,713.6
Commercial Revenues	2,155.3	1,152.9	—	—	—	—	3,308.2
Industrial Revenues	2,179.0	429.1	—	—	—	(0.9)	2,607.2
Other Retail Revenues	179.1	43.8	—	—	—	—	222.9
Total Retail Revenues	8,157.1	3,695.7	—	—	—	(0.9)	11,851.9
Wholesale and Competitive Retail Revenues:							
Generation Revenues	807.6	—	—	254.8	—	—	1,062.4
Transmission Revenues (a)	292.1	435.1	1,077.2	—	—	(825.0)	979.4
Renewable Generation Revenues (b)	—	—	—	57.3	—	—	57.3
Retail, Trading and Marketing Revenues (c)	—	—	—	1,480.7	—	(135.6)	1,345.1
Total Wholesale and Competitive Retail Revenues	1,099.7	435.1	1,077.2	1,792.8	—	(960.6)	3,444.2
Other Revenues from Contracts with Customers (b)	168.2	169.4	16.6	4.9	104.7	(147.1)	316.7
Total Revenues from Contracts with Customers	9,425.0	4,300.2	1,093.8	1,797.7	104.7	(1,108.6)	15,612.8
Other Revenues:							
Alternative Revenues (b)	(57.9)	32.3	(20.6)	—	—	(66.9)	(113.1)
Other Revenues (b)	—	150.0	—	59.9	(8.9)	(139.3)	61.7
Total Other Revenues	(57.9)	182.3	(20.6)	59.9	(8.9)	(206.2)	(51.4)
Total Revenues	$ 9,367.1	$ 4,482.5	$ 1,073.2	$ 1,857.6	$ 95.8	$ (1,314.8)	$ 15,561.4

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $794 million. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $136 million. The remaining affiliated amounts were immaterial.

	Year Ended December 31, 2018						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 3,751.8	$ 2,189.4	$ —	$ —	$ —	$ —	$ 5,941.2
Commercial Revenues	2,183.4	1,251.7	—	—	—	—	3,435.1
Industrial Revenues	2,212.8	512.5	—	—	—	—	2,725.3
Other Retail Revenues	183.5	42.7	—	—	—	—	226.2
Total Retail Revenues (a)	8,331.5	3,996.3	—	—	—	—	12,327.8
Wholesale and Competitive Retail Revenues:							
Generation Revenues	899.8	—	—	423.7	—	(7.3) (e)	1,316.2
Transmission Revenues (b)	282.2	372.1	849.3	—	—	(737.1)	766.5
Renewable Generation Revenues (c)	—	—	—	50.8	—	—	50.8
Retail, Trading and Marketing Revenues (d)	—	—	—	1,422.9	—	(120.7)	1,302.2
Total Wholesale and Competitive Retail Revenues	1,182.0	372.1	849.3	1,897.4	—	(865.1)	3,435.7
Other Revenues from Contracts with Customers (c)	158.4	204.6	15.2	20.6	86.2	(32.0)	453.0
Total Revenues from Contracts with Customers	9,671.9	4,573.0	864.5	1,918.0	86.2	(897.1)	16,216.5
Other Revenues:							
Alternative Revenues (c)	(15.9)	(22.2)	(60.4)	—	—	52.7	(45.8)
Other Revenues (c)	(10.5)	102.3	—	22.3	8.9	(98.0) (e)	25.0
Total Other Revenues	(26.4)	80.1	(60.4)	22.3	8.9	(45.3)	(20.8)
Total Revenues	$ 9,645.5	$ 4,653.1	$ 804.1	$ 1,940.3	$ 95.1	$ (942.4)	$ 16,195.7

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

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $643 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $121 million. The remaining affiliated amounts were immaterial.

(e) 2018 amounts have been revised to reflect the reclassification of $98 million of affiliated revenues between Generation Revenues and Other Revenues. This reclassification did not impact previously reported Total Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

The table below represents revenues from contracts with customers, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

	Year Ended December 31, 2020						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 563.6	$ —	$ 1,250.6	$ 794.1	$ 1,523.4	$ 579.4	$ 630.8
Commercial Revenues	366.7	—	517.0	499.3	682.0	320.1	466.7
Industrial Revenues	120.1	—	553.5	547.4	270.0	221.1	328.8
Other Retail Revenues	29.5	—	67.6	6.6	13.1	66.0	9.1
Total Retail Revenues	1,079.9	—	2,388.7	1,847.4	2,488.5	1,186.6	1,435.4
Wholesale Revenues:							
Generation Revenues (a)	—	—	230.2	274.6	—	15.1	162.0
Transmission Revenues (b)	399.9	1,210.3	130.8	29.0	67.0	27.5	111.2
Total Wholesale Revenues	399.9	1,210.3	361.0	303.6	67.0	42.6	273.2
Other Revenues from Contracts with Customers (c)	48.2	22.4	59.5	85.0	109.5	34.7	26.7
Total Revenues from Contracts with Customers	1,528.0	1,232.7	2,809.2	2,236.0	2,665.0	1,263.9	1,735.3
Other Revenues:							
Alternative Revenues (d)	3.4	(87.0)	(13.0)	5.8	66.6	2.2	3.2
Other Revenues (d)	87.5	—	—	—	17.5	—	—
Total Other Revenues	90.9	(87.0)	(13.0)	5.8	84.1	2.2	3.2
Total Revenues	$ 1,618.9	$ 1,145.7	$ 2,796.2	$ 2,241.8	$ 2,749.1	$ 1,266.1	$ 1,738.5

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $112 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 $952 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $69 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues.

	Year Ended December 31, 2019						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 571.5	$ —	$ 1,266.9	$ 730.0	$ 1,502.0	$ 650.2	$ 638.6
Commercial Revenues	411.5	—	559.9	494.2	738.5	388.5	485.4
Industrial Revenues	129.4	—	592.2	550.7	299.9	303.5	338.7
Other Retail Revenues	29.9	—	75.2	7.3	13.1	81.6	9.0
Total Retail Revenues	1,142.3	—	2,494.2	1,782.2	2,553.5	1,423.8	1,471.7
Wholesale Revenues:							
Generation Revenues (a)	—	—	251.5	402.4	—	39.5	194.7
Transmission Revenues (b)	379.2	1,025.5	103.6	25.1	56.0	27.5	106.7
Total Wholesale Revenues	379.2	1,025.5	355.1	427.5	56.0	67.0	301.4
Other Revenues from Contracts with Customers (c)	30.1	16.6	61.8	98.4	139.3	22.0	26.1
Total Revenues from Contracts with Customers	1,551.6	1,042.1	2,911.1	2,308.1	2,748.8	1,512.8	1,799.2
Other Revenues:							
Alternative Revenues (d)	0.6	(20.7)	13.6	(1.4)	31.7	(31.0)	(48.3)
Other Revenues (d)	157.1	—	—	—	17.1	—	—
Total Other Revenues	157.7	(20.7)	13.6	(1.4)	48.8	(31.0)	(48.3)
Total Revenues	$ 1,709.3	$ 1,021.4	$ 2,924.7	$ 2,306.7	$ 2,797.6	$ 1,481.8	$ 1,750.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $129 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $782 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $73 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Year Ended December 31, 2018						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 578.9	$ —	$ 1,342.7	$ 730.0	$ 1,611.6	$ 659.0	$ 641.6
Commercial Revenues	414.7	—	580.4	485.0	835.6	394.2	483.9
Industrial Revenues	128.0	—	604.3	565.6	385.2	304.0	333.7
Other Retail Revenues	29.4	—	77.4	7.2	12.9	83.6	8.6
Total Retail Revenues (a)	1,151.0	—	2,604.8	1,787.8	2,845.3	1,440.8	1,467.8
Wholesale Revenues:							
Generation Revenues (b)	—	—	250.4	470.5	—	36.3	216.8
Transmission Revenues (c)	313.4	816.9	82.7	23.1	58.5	40.2	108.4
Total Wholesale Revenues	313.4	816.9	333.1	493.6	58.5	76.5	325.2
Other Revenues from Contracts with Customers (d)	28.6	15.1	55.3	99.6	176.1	19.1	24.0
Total Revenues from Contracts with Customers	1,493.0	832.0	2,993.2	2,381.0	3,079.9	1,536.4	1,817.0
Other Revenues:							
Alternative Revenues (e)	(1.3)	(55.9)	(23.8)	(2.1)	(20.8)	10.9	4.9
Other Revenues (e)	103.6	—	(1.9)	(8.2)	4.3	—	—
Total Other Revenues	102.3	(55.9)	(25.7)	(10.3)	(16.5)	10.9	4.9
Total Revenues	$ 1,595.3	$ 776.1	$ 2,967.5	$ 2,370.7	$ 3,063.4	$ 1,547.3	$ 1,821.9

(a) 2018 amounts have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail Revenues. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $134 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $646 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $70 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(e) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

AEP has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. AEP subsidiaries elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for AEP's subsidiaries are summarized as follows:

Retail Revenues

AEP's subsidiaries within the Vertically Integrated Utilities and Transmission and Distribution Utilities segments have performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between AEP's subsidiaries and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice. Payments from REPs are due to AEP Texas within 35 days.

Wholesale Revenues - Generation

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments have performance obligations to sell electricity to wholesale customers from generation assets in PJM, SPP and ERCOT. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments also have performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales within the Vertically Integrated Utilities segment are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenues tables above.

APCo has a performance obligation to supply wholesale electricity to KGPCo through a PPA. The FERC regulates the cost-based wholesale power transactions between APCo and KGPCo. The purchased power agreement includes a component for the recovery of transmission costs under the FERC OATT. The transmission cost component of purchased power is cost-based and regulated by the Tennessee Regulatory Authority. APCo's performance obligation under the purchased power agreement is satisfied over time as KGPCo simultaneously receives and consumes the wholesale electricity. APCo's revenues from the purchased power agreement are presented within the Generation Revenues line in the disaggregated revenues tables above.

Wholesale Revenues - Transmission

AEP's subsidiaries within the Vertically Integrated Utilities, Transmission and Distribution Utilities and AEP Transmission Holdco segments have performance obligations to transmit electricity to wholesale customers through assets owned and operated by AEP subsidiaries. The performance obligation to provide transmission services in PJM, SPP and ERCOT encompass a time frame greater than a year, where the performance obligation within each RTO is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued monthly for SPP and ERCOT and weekly for PJM.

AEP subsidiaries within the PJM and SPP regions collect revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues tables above. AEP subsidiaries within the ERCOT region collect revenues through a combination of base rates and interim Transmission Costs of Services filings that are approved by the PUCT.

The AEP East Companies are parties to the TA, which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. PSO, SWEPCo and AEPSC are parties to the TCA by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. AEPTCo is a transmission owner within the PJM and SPP regions providing transmission services to affiliates in accordance with the OATT, TA and TCA. Affiliate revenues as a result of the respective TA and the TCA are reflected as Transmission Revenues in the disaggregated revenues tables above.

Marketing, Competitive Retail and Renewable Revenues

AEP's subsidiaries within the Generation & Marketing segment have performance obligations to deliver electricity to competitive retail and wholesale customers. Performance obligations for marketing, competitive retail and renewable offtake sales are satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are primarily variable as they are subject to customer's usage requirements; however, certain contracts mandate a delivery of a set quantity of electricity at a predetermined price, resulting in a fixed performance obligation.

Payment terms under marketing arrangements typically follow standard Edison Electric Institute and International Swaps and Derivatives Association terms, which call for payment in 20 days. Payments for competitive retail and offtake arrangements for renewable assets range from 15 to 60 days and are dependent on the product sold, location and the creditworthiness of customer. Invoices for marketing arrangements, competitive retail and offtake arrangements for renewable assets are issued monthly.

Fixed Performance Obligations

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of December 31, 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	2021	2022-2023	2024-2025	After 2025	Total
			(in millions)		
AEP	$ 1,122.9	$ 164.1	$ 162.2	$ 161.5	$ 1,610.7
AEP Texas	465.4	—	—	—	465.4
AEPTCo	1,319.5	—	—	—	1,319.5
APCo	173.4	32.3	23.2	11.6	240.5
I&M	35.1	8.8	8.8	4.5	57.2
OPCo	68.1	—	—	0.1	68.2
PSO	14.8	—	—	—	14.8
SWEPCo	41.6	—	—	—	41.6

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have any material contract assets as of December 31, 2020 and 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 any material contract liabilities as of December 31, 2020 and 2019.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrants' balance sheets within the Accounts Receivable - Customers line item. The Registrants' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of December 31, 2020 and 2019. See "Securitized Accounts Receivable - AEP Credit" section of Note 14 for additional information.

The following table represents the amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on the Registrant Subsidiaries' balance sheets:

	Years Ended December 31,	
Company	**2020**	**2019**
	(in millions)	
AEPTCo	$ 81.0	$ 65.9
APCo	52.7	47.3
I&M	34.8	37.1
OPCo	45.9	33.9
PSO	7.8	9.7
SWEPCo	11.2	17.6

Contract Costs

Contract costs to obtain or fulfill a contract for AEP subsidiaries within the Generation & Marketing segment are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current and noncurrent assets on the Registrants' balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Other Operation on the Registrants' income statements. The Registrants did not have material contract costs as of December 31, 2020 and 2019.

20. GOODWILL

The disclosure in this note applies to AEP only.

The changes in AEP's carrying amount of goodwill for the years ended December 31, 2020 and 2019 by operating segment are as follows:

	Corporate and Other	Generation & Marketing	AEP Consolidated
		(in millions)	
Balance as of December 31, 2018	$ 37.1	$ 15.4	$ 52.5
Impairment Losses	—	—	—
Balance as of December 31, 2019	37.1	15.4	52.5
Impairment Losses	—	—	—
Balance as of December 31, 2020	$ 37.1	$ 15.4	$ 52.5

In the fourth quarters of 2020 and 2019, annual impairment tests were performed. The fair values of the reporting units with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. AEP does not have any accumulated impairment on existing goodwill.

21. SUBSEQUENT EVENTS

Impacts of Severe Winter Weather in February 2021

In February 2021, many of AEP's service territories and customers were impacted by severe winter weather and extreme cold temperatures resulting in power outages, extensive damage to transmission and distribution infrastructure and disruption to the energy markets.

Storm Costs (Applies to AEP, APCo and SWEPCo)

Based on the information currently available, APCo, KPCo and SWEPCo currently estimate significant February 2021 storm restoration expenditures as shown in the table below. Management currently anticipates the storm restoration expenditures will be more heavily weighted towards other operation and maintenance expenses as compared to capital expenditures. Management will continue to refine these storm cost estimates as restoration efforts are completed and final costs become available.

	Total Estimated February 2021 Storm Restoration Expenditures		
	(in millions)		
APCo	$65.0	-	$75.0
KPCo	$75.0	-	$95.0
SWEPCo	$30.0	-	$40.0

Management plans to seek regulatory recovery of these costs. If any of the storm costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

February 2021 Severe Winter Weather Impacts in SPP (Applies to AEP, PSO and SWEPCo)

The February 2021 severe winter weather also had a significant impact in SPP resulting in the declaration of Energy Emergency Alert Levels 2 and 3 for the first time in SPP's history. The winter storm increased the demand for natural gas and restricted the available natural gas supply resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. From February 9, 2021, to February 20, 2021, based on the information currently available, PSO's and SWEPCo's preliminary estimates of natural gas expenses and purchases of electricity are as follows:

	PSO	SWEPCo
	(in millions)	
Estimated Natural Gas Expenses	$ 175.0	$ 375.0
Estimated Electricity Purchases	650.0	—
	$ 825.0	$ 375.0

The amounts in the table above represent preliminary estimates as of February 25, 2021, and are subject to final settlement as additional information becomes available. In addition, SPP notified PSO and SWEPCo of additional collateral requirements of approximately $868 million on a cumulative basis for the companies due March 2, 2021. Subsequently, SPP filed a waiver request with the FERC that would grant a limited waiver for Load Serving Entities to post this additional collateral requirement between February 24, 2021 and March 11, 2021. FERC approved the waiver request on February 24, 2021.

PSO and SWEPCo have active fuel clauses that allow for the recovery of prudently incurred fuel and purchased power expenses. Given the significance of these costs, PSO and SWEPCo expect regulators to perform a heightened review of the costs. Management believes these costs are probable of future recovery. However, the recovery of these costs from customers may be extended over longer than usual time periods to mitigate the impact on customer bills. Nevertheless, PSO and SWEPCo's payments to suppliers are due in March 2021.

PSO and SWEPCo are evaluating financing alternatives including funding contributions from Parent and long-term debt issuances to address the timing difference between the payment to suppliers and recovery from customers. If either PSO or SWEPCo is unable to recover these fuel and purchased power expenses or recover these expenses in a timely manner, it could reduce future net income and cash flows and impact financial condition.

ERCOT (Applies to AEP and AEP Texas)

In response to the extreme winter weather event, the Governor of Texas issued a Declaration of a State of Disaster for all counties in Texas. While recovery from the emergency conditions is continuing, some market conditions and activities have yet to return to normal. To assist with a return to normalcy, the PUCT issued an order that placed a temporary moratorium on customer disconnections due to non-payment for transmission and distribution utilities. This moratorium will be in effect until otherwise ordered by the PUCT.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing - The Company's common stock is traded principally on the NASDAQ Stock Market under the ticker symbol AEP.

Internet Home Page - Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings - Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 505005
Louisville, KY 40233-5005
For overnight deliveries:
Computershare Trust Company, N.A.
462 South 4th Street
Louisville, KY 40202
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders - (Stock held in a bank or brokerage account) - When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan - A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/stock.

Financial Community Inquiries - Institutional investors or securities analysts who have questions about the Company should direct inquiries to Darcy Reese, 614-716-2614, dlreese@aep.com; Individual shareholders should contact Rhonda Owens-Paul, 614-716-2819, rkowens-paul@AEP.com.

Number of Shareholders - As of February 24, 2021, there were approximately 55,282 registered shareholders and approximately 811,785 shareholders holding stock in street name through a bank or broker. There were 496,665,073 shares outstanding as of February 24, 2021.

Form 10-K - Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2020. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at rkowens-paul@AEP.com.

Executive Leadership Team

Name	Age	Office
Nicholas K. Akins	60	Chairman of the Board, President and Chief Executive Officer
Lisa M. Barton	55	Executive Vice President and Chief Operating Officer
Paul Chodak, III	57	Executive Vice President - Generation
David M. Feinberg	51	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	60	Executive Vice President and Chief Administrative Officer (Retired in 2020)
Mark C. McCullough	61	Executive Vice President - Energy Delivery
Charles R. Patton	61	Executive Vice President - External Affairs
Julia A. Sloat	51	Executive Vice President and Chief Financial Officer
Brian X. Tierney	53	Executive Vice President - Strategy
Charles E. Zebula	60	Executive Vice President - Energy Supply

Printed with inks containing soy and/or vegetable oils

MIX
Paper from responsible sources
FSC® C132107
www.fsc.org