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

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **September 30, 2022**
or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Transition Period from ____ to ____

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

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

Registrant	Title of each class	Trading Symbol	Name of Each Exchange on Which Registered
American Electric Power Company Inc.	Common Stock, $6.50 par value	AEP	The NASDAQ Stock Market LLC
American Electric Power Company Inc.	6.125% Corporate Units	AEPPZ	The NASDAQ Stock Market LLC

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit such files).
Yes ☒ No ☐

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

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

Smaller reporting company ☐ Emerging growth company ☐

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

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

Smaller reporting company ☐ Emerging growth company ☐

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

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

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

	Number of shares of common stock outstanding of the Registrants as of October 27, 2022
American Electric Power Company, Inc.	513,863,678
	($6.50 par value)
AEP Texas Inc.	100
	($0.01 par value)
AEP Transmission Company, LLC (a)	NA
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	3,680
	($18 par value)

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

NA Not applicable.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
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September 30, 2022

Part II. OTHER INFORMATION

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP Renewables	A division of AEP Energy Supply, LLC that develops and/or acquires large scale renewable projects that are backed with long-term contracts with creditworthy counter parties.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in deregulated markets.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AFUDC	Allowance for Equity Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to the under-recovered Expanded Net Energy Cost deferral balance.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
ATM	At-the-Market.
CAA	Clean Air Act.
CCR	Coal Combustion Residual.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
CO_2e	Carbon dioxide equivalent.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,296 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.

Term	Meaning
CSAPR	Cross-State Air Pollution Rule.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel XI, DCC Fuel XII, DCC Fuel XIII, DCC Fuel XIV, DCC Fuel XV, DCC Fuel XVI and DCC Fuel XVII, consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo. DHLC is a non-consolidated VIE of SWEPCo.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
ELG	Effluent Limitation Guidelines.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
Equity Units	AEP's Equity Units issued in August 2020 and March 2019.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
GHG	Greenhouse gas.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRA	On August 16, 2022 President Biden signed into law legislation commonly referred to as the "Inflation Reduction Act" (IRA).
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.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
Maverick	Maverick, part of the North Central Wind Energy Facilities, consists of 287 MWs of wind generation in Oklahoma.

Term	Meaning
MISO	Midcontinent Independent System Operator.
Mitchell Plant	A two unit, 1,560 MW coal-fired power plant located in Moundsville, West Virginia. The plant is jointly owned by KPCo and WPCo.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NAAQS	National Ambient Air Quality Standards.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NCWF	North Central Wind Energy Facilities, a joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,484 MWs of wind generation.
NOLC	Net Operating Loss Carryforwards.
NO_x	Nitrogen oxide.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
ODFA	Oklahoma Development Finance Authority.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
OTC	Over-the-counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
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 Credit.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants:AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Restoration Funding	AEP Texas Restoration Funding LLC, a wholly-owned subsidiary of AEP Texas and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Texas primarily caused by Hurricane Harvey.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.

Term	Meaning
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.
SEC	U.S. Securities and Exchange Commission.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019, consists of 724 MWs of wind generation and battery assets in the United States.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
Sundance	Sundance, acquired in April 2021 as part of the North Central Wind Energy Facilities, consists of 199 MWs of wind generation in Oklahoma.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA).The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
Transition Funding	AEP Texas Central Transition Funding III LLC, a wholly-owned subsidiary of AEP Texas and consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated VIE formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Traverse	Traverse, part of the North Central Wind Energy Facilities, consists of 998 MWs of wind generation in Oklahoma.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

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

- Changes in economic conditions, electric market demand and demographic patterns in AEP service territories.
- The impact of pandemics and any associated disruption of AEP's business operations due to impacts on economic or market conditions, costs of compliance with potential government regulations and employees' reactions to those regulations, electricity usage, supply chain issues, customers, service providers, vendors and suppliers.
- The economic impact of escalating global trade tensions including the conflict between Russia and Ukraine, and the adoption or expansion of economic sanctions or trade restrictions.
- 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 (i) if expected sources of capital, such as proceeds from the sale of assets or subsidiaries, do not materialize, and (ii) 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 transition from fossil generation and 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.
- The impact of federal tax legislation on results of operations, financial condition, cash flows or credit ratings.
- The risks before, during and after generation of electricity associated with the fuels used or the byproducts and wastes of such fuels, including coal ash and spent 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 and military conflicts, 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 the 2021 Annual Report and in Part II of this report.

The Registrants may use AEP’s website as a distribution channel for material company information. Financial and other important information regarding the Registrants is routinely posted on and accessible through AEP’s website at www.aep.com/investors/. In addition, you may automatically receive email alerts and other information about the Registrants when you enroll your email address by visiting the “Email Alerts” section at www.aep.com/investors/.

Company Website and Availability of SEC Filings

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

EXECUTIVE OVERVIEW

Customer Demand

AEP's weather-normalized retail sales volumes for the third quarter of 2022 increased by 2.6% from the third quarter of 2021. Weather-normalized residential sales decreased by 0.8% in the third quarter of 2022 from the third quarter of 2021. AEP's third quarter 2022 industrial sales volumes increased by 6.0% compared to the third quarter of 2021. The increase in industrial sales was spread across many industries. Weather-normalized commercial sales increased 3.4% in the third quarter of 2022 from the third quarter of 2021. The increase in commercial sales was spread across many sectors.

AEP's weather-normalized retail sales volumes for the nine months ended September 30, 2022 increased by 3.1% compared to the nine months ended September 30, 2021. Weather-normalized residential sales increased by 0.3% for the nine months ended September 30, 2022 compared to the nine months ended September 30, 2021. AEP's industrial sales volumes for the nine months ended September 30, 2022 increased by 5.5% compared to the nine months ended September 30, 2021. The increase in industrial sales was spread across many industries. Weather-normalized commercial sales increased 3.8% for the nine months ended September 30, 2022 compared to the nine months ended September 30, 2021. The increase in commercial sales was spread across many sectors.

Supply Chain Disruption and Inflation

The Registrants have experienced certain supply chain disruptions driven by several factors including staffing and travel issues caused by the COVID-19 pandemic, international tensions including the ramifications of regional conflict, increased demand due to the economic recovery from the pandemic, inflation, labor shortages in certain trades and shortages in the availability of certain raw materials. These supply chain disruptions have not had a material impact on the Registrants net income, cash flows and financial condition, but have extended lead times for certain goods and services and have contributed to higher prices for fuel, materials, labor, equipment and other needed commodities. Management has implemented risk mitigation strategies in an attempt to mitigate the impacts of these supply chain disruptions. The United States economy has encountered a significant level of inflation that has contributed to increased uncertainty in the outlook of near-term economic activity, including whether inflation will continue and at what rate. A prolonged continuation or a further increase in the severity of supply chain and inflationary disruptions could result in additional increases in the cost of certain goods and services and further extend lead times which could reduce future net income and cash flows and impact financial condition.

Strategic Evaluation of AEP Energy

AEP has initiated a strategic evaluation for its ownership in AEP Energy, a wholly-owned retail energy supplier that supplies electricity and/or natural gas to residential, commercial and industrial customers. AEP Energy provides various energy solutions in Illinois, Pennsylvania, Delaware, Maryland, New Jersey, Ohio and Washington, D.C. AEP Energy had approximately 672,000 customer accounts as of September 30, 2022. Potential alternatives may include, but are not limited to, continued ownership or a sale of all or a part of AEP Energy. Management has not made a decision regarding the potential alternatives, but expects to complete the strategic evaluation in the first half of 2023.

Federal Tax Legislation

On August 16, 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022 or IRA. Most notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer of tax credits to third parties for cash.With the exception of PTCs and ITCs, this legislation is prospective and has no material impact on the current period financial statements. As significant guidance from Treasury and the IRS is expected on the tax provisions in the IRA, AEP will continue to monitor any issued guidance and evaluate the impact on future net income, cash flows and financial condition.

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 November 2020, the Virginia SCC issued an order on APCo's 2017-2019 Triennial Review filing 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).

  In August 2022, the Virginia Supreme Court issued its opinion on submitted appeals of APCo's 2017-2019 Virginia Triennial Review concluding that the Virginia SCC: a) erred in finding it was not reasonable for APCo to record all remaining costs associated with early retirement of certain coal-fired generating plants in the 2017-2019 earnings test period, b) did not err by ordering APCo to retroactively implement depreciation rates for the years 2018 and 2019 and c) did not err in finding that APCo's affiliate costs from OVEC were reasonable. The Virginia Supreme Court then remanded the issue regarding the retired coal-fired plants back to the Virginia SCC for further proceedings.

  In September 2022, and in response to the Virginia Supreme Court opinion and subsequent Virginia SCC order initiating a remand proceeding, APCo submitted to the Virginia SCC: (a) an updated 2017-2019 Virginia earnings calculation resulting in a proposed $37 million regulatory asset related to previously incurred costs that APCo is expecting to recover as a result of earning below its 2017-2019 authorized ROE band, (b) an updated requested annual base rate increase of $41 million effective October 2022 and (c) a requested rider to recover, over the period October 2022 through January 2024, approximately $72 million related to an APCo Virginia base rate increase for the period January 2021 through September 2022. APCo's requested $41 million annual base rate increase includes approximately $12 million related to the recovery of APCo's regulatory asset for previously incurred costs as a result of earning below its 2017-2019 authorized ROE band. APCo implemented interim base rate and rider rate increases effective October 2022, both of which are subject to refund and review by the Virginia SCC.An order from the Virginia SCC in the remand proceeding is expected in the fourth quarter of 2022.

  In September 2022, APCo expensed the remaining $25 million closed coal plant regulatory asset that was previously ordered by the Virginia SCC and recorded a $37 million regulatory asset for previously incurred costs that APCo is expecting to recover as a result of earning below its 2017-2019 authorized ROE band.APCo's October 2022 through January 2024 net income, cash flows and financial condition is expected to be positively impacted pending the Virginia SCC's order on APCo's requested base rate and rider rate increases.

- *2020-2022 Virginia Triennial Review* - In March 2023, APCo will submit its required Virginia earnings test calculation for the 2020-2022 Triennial Review period. For Triennial Review periods in which a Virginia utility earns below its authorized ROE band, the utility may file to recover expenses incurred, up to the bottom of the authorized ROE band, related to major storms, the early retirement of fossil fuel generating assets and certain projects necessary to comply with state and federal environmental legislation. As of September 2022, APCo has deferred approximately $25 million related to previously incurred costs as a result of the current estimate that APCo will earn below the bottom of its authorized ROE band during the 2020-2022 Triennial Review period.If it is determined that APCo has earned above the bottom of its authorized ROE band for the 2020-2022 Triennial Review period it could reduce future net income and cash flows and impact financial conditions.

- *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.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. 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 March 2021, the Texas Supreme Court issued an opinion reversing the July 2018 judgment of the Texas Third Court of Appeals and agreeing with the PUCT's judgment affirming the prudence of the Turk Plant.In addition, the Texas Supreme Court remanded the AFUDC dispute back to the Texas Third Court of Appeals. No parties filed a motion for rehearing with the Texas Supreme Court. In August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgment affirming the PUCT's order on AFUDC, concluding that the language of the PUCT's original 2008 order intended to include AFUDC in the Texas jurisdictional capital cost cap, and remanded the case to the PUCT for future proceedings. SWEPCo disagrees with the Court of Appeals decision.SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court in November 2021.In October 2022, the Texas Supreme Court denied the Petitions for Review submitted by SWEPCo and the PUCTSWEPCo plans to file a request for rehearing.If SWEPCo's request for rehearing is denied, the case will be remanded to the PUCT for future proceedings.

  Management does not believe a disallowance of capitalized Turk Plant costs or a revenue refund is probable as of September 30, 2022. However, if SWEPCo is ultimately unable to recover AFUDC in excess of the Texas jurisdictional capital cost cap it would be expected to result in a pretax net disallowance ranging from $80 million to $90 million. In addition, if AFUDC is ultimately determined to be included in the Texas jurisdictional capital cost cap, SWEPCo estimates it may be required to make customer refunds ranging from $0 to $180 million related to revenues collected from February 2013 through September 2022 and such determination may reduce SWEPCo's future revenues by approximately $15 million on an annual basis.

- In July 2019, Ohio House Bill 6 (HB 6), which offered incentives for power-generating facilities with zero or reduced carbon emissions, was signed into law by the Ohio Governor. HB 6 terminated energy efficiency programs as of December 31, 2020, including OPCo's shared savings revenues of $26 million annually and phased out renewable mandates after 2026. HB 6 also provided for continued recovery of existing renewable energy contracts on a bypassable basis through 2032 and included a provision for continued recovery of OVEC costs through 2030 which is allocated to all electric distribution utility customers in Ohio 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 an alleged racketeering conspiracy involving the adoption of HB 6. Certain defendants in that case have since pleaded guilty. In 2021, four AEP shareholders filed derivative actions purporting to assert claims on behalf of AEP against certain AEP officers and directors. See Litigation Related to Ohio House Bill 6 section of Litigation below for additional information.

In March 2021, the Governor of Ohio signed legislation that, among other things, repealed the payments to the nonaffiliated owner of Ohio's nuclear power plants that were previously authorized under HB 6. The new legislation, House Bill 128, went into effect in May 2021 and leaves unchanged other provisions of HB 6 regarding energy efficiency programs, recovery of renewable energy costs and recovery of OVEC costs. To the extent that the law changes or OPCo is unable to recover the costs of renewable energy contracts on a bypassable basis by the end of 2032, recover costs of OVEC after 2030 or incurs significant costs associated with the derivative actions, it could reduce future net income and cash flows and impact financial condition.

- In April 2021, the FERC issued a supplemental Notice of Proposed Rulemaking (NOPR) proposing to modify its incentive for transmission owners that join RTOs (RTO Incentive). Under the supplemental NOPR, the RTO Incentive would be modified such that a utility would only be eligible for the RTO Incentive for the first three years after the utility joins a FERC-approved Transmission Organization. This is a significant departure from a previous NOPR issued in 2020 seeking to increase the RTO Incentive from 50 basis points to 100 basis points. The supplemental NOPR also required utilities that have received the RTO Incentive for three or more years to submit, within 30 days of the effective date of a final rule, a compliance filing to eliminate the incentive from its tariff prospectively. The supplemental NOPR was subject to a 60 day comment period followed by a 30 day period for reply comments. In July 2021, AEP submitted reply comments. AEP is awaiting a final rule from the FERC.

  In July 2021, the FERC issued an order denying Dayton Power and Light's request for a 50 basis point RTO incentive on the basis that its RTO participation was not voluntary, but rather is required by Ohio law. This precedent could have an adverse impact on AEP's Ohio transmission owning subsidiaries. In its February 2022 order on rehearing, the FERC affirmed the decision in its July 2021 order. The case is currently pending appeal at the United States Court of Appeals for the Sixth Circuit. In May 2022, the United States Court of Appeals for the Sixth Circuit issued an order to hold the appeal in abeyance pending resolution of FERC proceedings on the Office of the Ohio Consumers' Counsel's February 2022 RTO Incentive Complaint.

  In 2019, the 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 2020, the FERC determined the base ROE for MISO's transmission owning subsidiaries should be 10.02% (10.52% inclusive of RTO Incentive adder of 0.5%).

  If the FERC modifies its RTO Incentive policy, it 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. Based on management's preliminary estimates, if a final rule is adopted consistent with the April 2021 supplemental NOPR, it could reduce AEP's pretax income by approximately $55 million to $70 million on an annual basis.

- *FERC RTO Incentive Complaint* - In February 2022, the Office of the Ohio Consumers' Counsel filed a complaint against AEPSC, American Transmission Systems, Inc. and Duke Energy Ohio, alleging the 50 basis point RTO incentive included in Ohio Transmission Owners' respective transmission formula rates is not just and reasonable and therefore should be eliminated on the basis that RTO participation is not voluntary, but rather is required by Ohio law. In March 2022, AEPSC filed a motion to dismiss the Ohio Consumers' Counsel's February 2022 complaint with the FERC on the basis of certain deficiencies, including that the complaint fails to request relief that can be granted under FERC regulations because AEPSC is not a public utility nor does it have a transmission rate on file with the FERC. Management believes its financial statements adequately address the impact of the February 2022 complaint. If the

FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

- *2021 Louisiana Storm Cost Filing* -In 2020, Hurricanes Laura and Delta caused power outages and extensive damage to the SWEPCo service territories, primarily impacting the Louisiana jurisdiction. Following both hurricanes, the LPSC issued orders allowing Louisiana utilities, including SWEPCo, to establish regulatory assets to track and defer expenses associated with these storms.In February 2021, severe winter weather impacted the Louisiana jurisdiction and in March 2021, the LPSC approved the deferral of incremental storm restoration expenses related to the winter storm. In October 2021, SWEPCo filed a request with the LPSC for recovery of $145 million in deferred storm costs associated with the three storms. As part of the filing, SWEPCo requested recovery of the carrying charges on the deferred regulatory asset at a weighted average cost of capital through a rider beginning in January 2022. In May 2022, LPSC staff testimony was submitted to the LPSC. In July 2022, SWEPCo filed rebuttal testimony which agreed to make a request for securitization of the deferred storm costs as the LPSC staff had recommended in their testimony. An order is expected before the end of 2022. If any of the storm costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

- In February 2021, severe winter weather 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. As a result of the severe winter weather, PSO and SWEPCo incurred approximately $1.1 billion of extraordinary fuel costs and purchases of electricity, which were deferred as regulatory assets.

  In April 2021, the OCC approved the deferral of PSO's extraordinary fuel costs and purchases of electricity as regulatory assets, including a carrying charge at an interim rate of 0.75%, over a longer time period than what the FAC traditionally allows. Also in April 2021, legislation was enacted in Oklahoma permitting securitized financing of qualified costs from extreme weather events. This legislation provides certain authority to the OCC to approve amounts to be recovered from the issuance of ratepayer-backed securitized bonds issued by the ODFA, an Oklahoma governmental agency. In January 2022, PSO, OCC staff and certain intervenors filed a joint stipulation and settlement agreement with the OCC to approve the securitization of PSO's extraordinary fuel costs and purchases of electricity.In February 2022, the OCC approved the joint stipulation and settlement agreement which included a determination that all of PSO's extraordinary fuel costs and purchases of electricity were prudent and reasonable and also provided a 0.75% carrying charge related to those costs, subject to true-up based on actual financing costs.

  In September 2022, PSO received proceeds of $687 million from the ODFA which issued ratepayer-backed securitization bonds for the purpose of reimbursing PSO for extraordinary fuel costs and purchases of electricity incurred during the February 2021 severe winter weather event, which were previously recorded as Regulatory Assets on PSO's balance sheet. The securitization bonds are the obligation of the ODFA and there is no recourse against PSO in the event of a bond default, and therefore are not recorded as Long-term Debt on PSO's balance sheet. PSO will serve as the servicing agent of the bonds and is responsible for the routine billing and collection of the securitization charges and remitting those collections back to the ODFA. The securitization charges billed to and collected from customers are not included as revenue on PSO's statement of income. The collections from customers will occur over 20 years.

  In March 2021, the APSC issued an order authorizing recovery of the Arkansas jurisdictional share of the retail customer fuel costs over five years, with the appropriate carrying charge to be determined at a later date. Subsequently, SWEPCo began recovery of these fuel costs.In April 2021, SWEPCo filed testimony supporting a five-year recovery with a carrying charge of 6.05%.In June 2022, the APSC ordered SWEPCo to recover the Arkansas jurisdictional share of the fuel costs over six years with a carrying charge equal to its weighted average cost of capital, subject to a prudency review and true-up.

In March 2021, the LPSC approved a special order granting a temporary modification to the FAC and shortly after SWEPCo began recovery of its Louisiana jurisdictional share of these fuel costs based on a five-year recovery period inclusive of an interim carrying charge of 3.25%. SWEPCo will work with the LPSC to finalize the actual recovery period and determine the appropriate carrying charge in future proceedings.

In August 2021, SWEPCo filed an application with the PUCT to implement a net interim fuel surcharge for the Texas jurisdictional share of these retail fuel costs. The application requested a five-year recovery with a carrying charge of 7.18%. In March 2022, the PUCT ordered SWEPCo to recover the Texas jurisdictional share of the fuel costs over five years with a carrying charge of 1.65% and ordered SWEPCo to file a fuel reconciliation addressing fuel costs from January 1, 2020 through December 31, 2021.

As of September 30, 2022, SWEPCo had regulatory assets of $349 million relating to natural gas expenses and purchases of electricity incurred during the February 2021 severe winter weather event. SWEPCo's deferred regulatory asset consists of $85 million, $126 million and $138 million related to the Arkansas, Louisiana and Texas jurisdictions, respectively.

If SWEPCo is unable to recover any of the costs relating to the extraordinary fuel and purchases of electricity, or obtain authorization of a reasonable carrying charge on these costs, it could reduce future net income and cash flows and impact financial condition.

- AEP transitioned to stand-alone treatment of NOLC in its PJM and SPP transmission formula rates beginning with 2022 projected transmission revenue requirements and 2021 true-up to actual transmission revenue requirements, and provided notice of this change in informational filings made with the FERC. Stand-alone treatment of the NOLCs for transmission formula rates increased the 2021 and 2022 annual revenue requirements by $78 million and $60 million, respectively. Through the third quarter of 2022, the Registrants' financial statements reflect a provision for refund for all NOLC revenues billed by PJM and SPPAlso, the impact of inclusion of the NOLC in the 2021 annual formula rate true-up not yet billed by PJM and SPP is not reflected in the Registrants' revenues and expenses as the Registrants have not met the requirements of alternative revenue recognition in accordance with the accounting guidance for "Regulated Operations".

  AEP is also transitioning to stand-alone treatment of NOLC in retail jurisdiction base rate case filings.As a result of retail jurisdiction base rate cases in Arkansas, Indiana, Oklahoma and Texas, inclusion of NOLCs in rates in those jurisdictions is contingent upon a supportive private letter ruling from the IRS.

- *SPP Capacity Planning Reserve Margin* -In July 2022, SPP approved a plan to increase its capacity planning reserve margin from 12% to 15% starting in the summer of 2023. Compliance filings are due to SPP in February 2023 and any deficiencies are required to be remedied by May 2023. SPP's annual non-compliance charge as a result of not meeting capacity requirements could range from approximately $86 thousand per MW to approximately $171 thousand per MW. Non-compliance could also result in a failure to meet NERC criteria and violating SPP's tariff before FERC.As of September 30, 2022, the increase in the capacity planning reserve margin for PSO and SWEPCo to comply with this new SPP requirement is approximately 265 MWs.Management is currently evaluating options and expects to comply with SPP's 2023 capacity planning reserve margin requirements. If PSO or SWEPCo incur charges or are unable to recover, or experience delays in recovering, the costs of complying with SPP's rule, it could reduce future net income and cash flows and impact financial condition.

Utility Rates and Rate Proceedings

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

The following tables show the Registrants' completed and pending base rate case proceedings in 2022. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase		Approved ROE	New Rates Effective
		(in millions)			
SWEPCo	Texas	$ 39.4		9.25%	March 2021
I&M	Indiana	61.4	(a)	9.7%	February 2022
SWEPCo	Arkansas	48.7		9.5%	July 2022
KGPCo	Tennessee	5.8		9.5%	August 2022

(a) See "2021 Indiana Base Rate Case "Section of Note 4 - Rate Matters in the 2021 Annual Report for additional information.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase	Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE
			(in millions)		
SWEPCo	Louisiana	December 2020	$ 94.7	10.35%	9.1%-9.8%

Deferred Fuel Costs

Increased fuel and purchased power prices in excess of amounts included in fuel-related revenues has led to an increase in the under collection of fuel costs from customers in most jurisdictions. The table below illustrates the increase (decrease) in the deferred fuel regulatory assets by company and jurisdiction, excluding the impacts of the February 2021 severe winter weather event. See the "February 2021 Severe Winter Weather Impacts in SPP" sections in Note 4 for additional information.

Company	Jurisdiction	Traditional FAC Recovery Reset	As of September 30, 2022	As of December 31, 2021	Increase/ (Decrease)
APCo	Virginia (a)	Annually	$ 359.5	$ 128.6	$ 230.9
APCo	West Virginia	Annually	235.2	72.7	162.5
I&M	Indiana	Bi-Annually	19.2	—	19.2
I&M	Michigan	Annually	6.2	6.4	(0.2)
PSO	Oklahoma (b)	Annually	419.9	194.6	225.3
SWEPCo	Arkansas	Annually	67.7	23.1	44.6
SWEPCo	Louisiana	Monthly	2.4	11.1	(8.7)
SWEPCo	Texas	Tri-Annually	165.9	47.0	118.9
KPCo	Kentucky	Monthly	24.4	8.2	16.2
WPCo	West Virginia	Annually	195.2	101.6	93.6
		Total (c)	$ 1,495.6	$ 593.3	$ 902.3

(a) Includes $191 million of noncurrent deferred fuel classified as a Regulatory Asset on APCo's balance sheets as of September 30, 2022.
(b) Includes $241 million of noncurrent deferred fuel classified as a Regulatory Asset on PSO's balance sheets as of September 30, 2022.
(c) Includes $24 million and $8 million as of September 30, 2022 and December 31, 2021, respectively, of deferred fuel classified as Assets Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

The AEP utility subsidiaries are working with various state commissions on the timing of recovering deferred fuel balances and have made the following recent filings:

In April 2022, APCo and WPCo submitted their 2022 annual ENEC filing with the WVPSC requesting a $297 million annual increase in ENE revenues, effective September 1, 2022. The WVPSC requested West Virginia staff perform a prudency review of APCo and WPCo's actual and forecasted ENEC costs.Management expects to receive a WVPSC order on the 2022 ENEC filing in the fourth quarter of 2022 and a separate WVPSC order on the prudency review of the ENEC costs in the first quarter of 2023See "2021 and 2022 ENEC Filings" section of Note 4 for additional information.

In August 2022, PSO requested an interim update to its annual Fuel Cost Adjustment (FCA) rates in accordance with the terms of the established tariff which allows PSO or the OCC staff to request an interim FCA adjustment in the event that the annual FCA over/under-recovered balance is $50 million or more on a cumulative basis. In September 2022, the Director of the Public Utility Division of the OCC approved a FCA rate designed to collect a $402 million deferred fuel balance over a 27 month period, effective with the first billing cycle of October 2022. PSO's fuel and purchased power expenses are subject to an annual prudency review by the OCC.

In September 2022, APCo submitted a request to the Virginia SCC to increase its annual fuel factor by approximately $279 millionAPCo will implement interim FAC rates effective November 2022 subject to Virginia SCC review.To help mitigate the impact of rising fuel costs on customer bills, APCo proposed to recover its deferred fuel balance as of October 31, 2022 over two years. An order from the Virginia SCC is expected in the first quarter of 2023.

In September 2022, SWEPCo filed a request with the APSC for an interim increase to its current Energy Cost Rate (ECR) to recover $44 million of additional fuel costs incurred from April 2022 through August 2022, subsequent to the last annual ECR rate change. The interim rate will be effective with the first billing cycle of October 2022 and will be in effect for six months until the ECR is reset in April 2023.

Dolet Hills Power Station and Related Fuel Operations

In 2020, 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. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining. In December 2021, the Dolet Hills Power Station was retired. While in operation, DHLC provided 100% of the fuel supply to Dolet Hills Power Station.

The remaining book value of Dolet Hills Power Station non-fuel related assets are recoverable by SWEPCo through a combination of base rates and rate riders. As of September 30, 2022, SWEPCo's share of the net investment in the Dolet Hills Power Station was $113 million, including materials and supplies, net of cost of removal collected in rates.

Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses and are subject to prudency determinations by the various commissions. After closure of the DHLC mining operations and the Dolet Hills Power Station, additional reclamation and other land-related costs incurred by DHLC and Oxbow will continue to be billed to SWEPCo and included in existing fuel clauses. As of September 30, 2022, SWEPCo had a net under-recovered fuel balance of $236 million, inclusive of costs related to the Dolet Hills Power Station billed by DHLC, but excluding impacts of the February 2021 severe winter weather event.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to $20 million of fuel costs in 2021 and defer approximately $30 million of additional costs with a recovery period to be determined at a later date. In August 2022, the LPSC staff filed testimony recommending fuel disallowances of $72 million, including denial of recovery of the $30 million deferral, with refunds to customers over five years. In September 2022, SWEPCO filed rebuttal testimony addressing the LPSC staff recommendations.

In March 2021, the APSC approved fuel rates that provide recovery of $20 million for the Arkansas share of the 2021 Dolet Hills Power Station fuel costs over five years through the existing fuel clause.

In August 2022, SWEPCo filed a fuel reconciliation with the PUCT covering the fuel period of January 1, 2020 through December 31, 2021.

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

Pirkey Plant and Related Fuel Operations

In 2020, management announced plans to retire the Pirkey Plant in 2023. The Pirkey Plant non-fuel costs are recoverable by SWEPCo through base rates and fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions. As of September 30, 2022, SWEPCo's share of the net investment in the Pirkey Plant was $216 million, including CWIP, before cost of removal. Sabine is a mining operator providing mining services to the Pirkey 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 $49 million as of September 30, 2022. As of September 30, 2022, SWEPCo had a net under-recovered fuel balance of $236 million, inclusive of costs related to the Pirkey Plant billed by Sabine, but excluding impacts of the February 2021 severe winter weather event. Upon cessation of lignite deliveries by Sabine to the Pirkey Plant, additional operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in existing 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

In recent years, AEP has developed its renewable portfolio within the Generation & Marketing segment.Other activities have included, but are not limited to, 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 developed and/or acquired large scale renewable generation projects that are backed with long-term contracts with creditworthy counterparties.

In February 2022, AEP management announced the initiation of a process to sell all or a portion of AEP Renewables' competitive contracted renewables portfolio within the Generation & Marketing segment. Subsequently, AEP's investment in Flat Ridge 2 Wind LLC was removed from the competitive contracted renewables sale portfolio. In June 2022, as a result of deteriorating financial performance, sale negotiations and AEP's ongoing evaluation and ultimate decision to exit the investment in the near term, AEP recorded a pretax other than temporary impairment charge of $186 million in Equity Earnings (Losses) of Unconsolidated Subsidiaries in AEP's Statement of IncomeIn the third quarter of 2022, AEP recorded an additional $2 million pretax other than temporary impairment charge. The carrying value of AEP's investment in Flat Ridge 2 was not material to AEP as of September 30, 2022. In September 2022, AEP signed a Purchase and Sale Agreement with a nonaffiliate for AEP's interest in Flat Ridge 2, subject to FERC approval.Management expects the transaction to close in the fourth quarter of 2022 and have an immaterial impact on the financial statements. See "Impairments" section of Note 6 for additional information.

As of September 30, 2022, excluding Flat Ridge 2, the competitive contracted renewable portfolio assets totaled 1.4 gigawatts of generation resources representing consolidated solar and wind assets, with a net book value of $1.2 billion, and a 50% interest in five joint venture wind farms, totaling $246 million, accounted for as equity method investments. The anticipated disposition of all or a portion of the AEP Renewables' portfolio has not met the accounting requirements to be presented as Held for Sale as of September 30, 2022.If AEP is unable to recover the book value or carrying value of these assets through a sales process, it could reduce future net income and impact financial condition.

Regulated Renewable Generation Facilities

North Central Wind Facilities

In 2020, PSO and SWEPCo received regulatory approvals to acquire the NCWF, comprised of three Oklahoma wind facilities totaling 1,484 MWs, o a fixed cost turn-key basis at completion. PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively. Output from the NCWF serves retail load in PSO's Oklahoma service territory and both retail and FERC wholesale load in SWEPCo's service territories i Arkansas and Louisiana. The Oklahoma and Louisiana portions of the NCWF revenue requirement, net of PTC benefit, are recoverable througl authorized riders beginning at commercial operation and until such time as amounts are reflected in base rates. The Arkansas portion of the NCWF revenue requirement was approved for recovery through base rates in the 2021 Arkansas Base Rate Case. The table below provides a summary of the facilities as of September 30, 2022:

Project	In-Service Date	Net Book Value	Federal PTC Qualification % (a)		Generating Capacity
		(in millions)			(in MWs)
Sundance	April 2021	$ 282.3	100 %		199
Maverick	September 2021	398.3	80 %		287
Traverse	March 2022	1,255.0	100 %	(b)	998

(a) PTC benefits are available for a ten year period following the in-service date.
(b) The PTC for Traverse was increased to 100% in the third quarter of 2022 as a result of the IRA legislation.

See "North Central Wind Energy Facilities" section of Note 6 for additional information.

Recent Renewable Generation Filings

In December 2021 and January 2022, APCo filed petitions with the Virginia SCC and WVPSC, respectively, for prudency and cost recovery of: (a an APCo-owned 204 MW wind generation facility, (b) three APCo-owned solar generation facilities totaling 205 MWs and (c) three solar purchased power agreements (PPAs) totaling 89 MWs. In June 2022, the WVPSC approved APCo's January 2022 petition for cost recovery of an APCo-owned 50 MW solar generation facility which was included within the 205 MWs requested. In July 2022, the Virginia SCC approved APCo's December 2021 petition for prudency and cost recovery as submitted. An order from the WVPSC is anticipated in the fourth quarter of 2022 related to the remaining items in APCo's January 2022 petition. In September 2022, APCo received a notice of termination for a 19 MW Solar PPA due to the developer being unsuccessful in obtaining local permits. The 19 MW Solar PPA was included in the December 2021 and January 2022 petitions filed with the Virginia SCC and WVPSC, respectively. If the WVPSC does not approve one or more of the projects included in APCo's January 2022 petition, the associated allocation of cost and production of the facilities will be assigned to Virginia retail customers. Under separate, existing APCo Virginia and West Virginia tariffs, APCo is also authorized for cost recovery of an additional 40 MWs of recently completed solar PPAs.

In May 2022, SWEPCo submitted filings before the APSC, LPSC and PUCT requesting approval to acquire three renewable energy projects totalir 999 MWs. In October 2022, SWEPCo also submitted the necessary filings with the FERCThe projects are comprised of two wind facilities, totaling 799 MWs, and one solar facility, totaling 200 MWs. One of the wind facilities, totaling approximately 201 MWs, is expected to reach commercial operation in December 2024 with the remaining facilities expected to reach commercial operation in December 2025.

Significant Renewable Generation Requests for Proposal (RFP)

As part of AEP's transition to diversify the company's generation resources and build its renewable generation portfolio, the Registrants file RFPs in an effort to identify potential wind and solar projects. The table below includes the significant RFPs recently issued.These projects would be subject to regulatory approval.

Company	Issuance Date	Generation Type	Owned/ PPA	Generating Capacity
				(in MWs)
APCo	January 2022	Wind	Owned	1,000
APCo	January 2022	Solar (a)	Owned	100
APCo	February 2022	Solar	Owned	150
APCo	June 2022	Solar/Wind	PPA	100
I&M	March 2022	Wind	Owned	800
I&M	March 2022	Solar (a)	Owned	500
PSO	November 2021	Wind	Owned	2,800
PSO	November 2021	Solar (a)	Owned	1,350
SWEPCo	September 2022	Wind	Owned	1,900
SWEPCo	September 2022	Solar (a)	Owned	500
Total Significant RFP's				**9,200**

(a) Includes an option for battery storage.

Disposition of KPCo and KTCo

In October 2021, AEP entered into a Stock Purchase Agreement (SPA) to sell KPCo and KTCo to Liberty Utilities Co., a subsidiary of Algonqui Power & Utilities Corp. (Liberty), for approximately a $2.85 billion enterprise value.In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. AEP has received clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and the Committee on Foreign Investment in the United States.The sale remains subject to FERC approval under Section 203 of the Federal Power Act.

In September 2022, AEP, AEPTCo and Liberty entered into an amendment (Amendment) to the SPA which reduced the purchase price to approximately $2.646 billion and Liberty agreed to waive, upon FERC approval of the sale, the SPA condition precedent to closing requiring the issuance of regulatory orders approving a new proposed Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo.The Amendment also provided that the closing shall not occur prior to January 4, 2023, unless mutually agreed to by AEP and Liberty.

Mitchell Plant Operations and Maintenance Agreement and Ownership Agreement

KPCo and WPCo each own a 50% undivided interest in the 1,560 MW coal-fired Mitchell PlantAs of September 30, 2022, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $576 million.

In November 2021, AEP made filings with the KPSC, WVPSC and FERC seeking approval of a new proposed Mitchell Plant Operations ar Maintenance Agreement and Mitchell Plant Ownership Agreement.In February 2022, AEP filed a motion to withdraw its filing with the FERC.The KPSC and WVPSC issued orders addressing AEP's filings in May 2022 and July 2022Those orders proposed materially different modifications to the Mitchell Plant agreements filed by AEP such that the new agreements could not be executed by the parties.In lieu of new agreements, in July 2022, KPCo and WPCo confirmed with the KPSC and WVPSC, respectively, that they will continue operating under the existing Mitchell Agreemen utilizing the Mitchell Agreement Operating Committee's authority under that agreement to issue appropriate resolutions so the parties can operate in accordance with each state commission's directives related to CCR and ELG investment. In September 2022, pursuant to resolutions under the existing Mitchell Plant agreement, WPCo replaced KPCo as the Operator of Mitchell Plant.

Transfer of Ownership

FERC Proceedings

In December 2021, Liberty, KPCo and KTCo requested FERC approval of the sale under Section 203 of the Federal Power Act. In February 2022, several intervenors in the case filed protests related to whether the sale will negatively impact the wholesale transmission rates of applicants. In April 2022, the FERC issued a deficiency letter stating that the Section 203 application is deficient and that additional information is required to process it. In May 2022, Liberty, KPCo and KTCo supplemented the application and in June 2022, the FERC issued an order formally notifying AEP that it was exercising its ability to take up to an additional 180 days to act on the application. An order from the FERC is expected in the fourth quarter of 2022.

KPSC Proceedings

In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to conditions contingent upon the closing of the sale, including establishment of regulatory liabilities to subsidize retail customer transmission and distribution expenses, a fuel adjustment clause bill credit, and a three-year Big Sandy decommissioning rider rate holiday during which KPCo's carrying charge is reduced by 50%. As a result of the conditions imposed by KPSC, in the second quarter of 2022, AEP recorded a $69 million loss on the expected sale of the Kentucky Operations in accordance with accounting guidance for Fair Value Measurement.

Further, as a result of the Amendment and the change to the anticipated timing of the completion of the transaction, AEP recorded an additional $194 million pretax loss ($149 million net of tax) on the expected sale of the Kentucky Operations in the third quarter of 2022 in accordance with the accounting guidance for Fair Value Measurement. AEP recorded a $263 million pretax loss ($218 million net of tax) on the expected sale of the Kentucky Operations for the nine months ended September 30, 2022. AEP expects cash proceeds, net of taxes and transaction fees, from the sale of approximately $1.2 billion.

Subject to receipt of FERC authorization under Section 203 of the Federal Power Act, the sale is expected to close in January 2023 with Liberty acquiring the assets and assuming the liabilities of KPCo and KTCo, excluding pension and other post-retirement benefit plan assets and liabilities. AEP expects to provide customary transition services to Liberty for a period of time after closing of the transaction. AEP plans to use the proceeds from the sale to fund its continued investment in regulated businesses, including transmission and regulated renewables projects. If additional reductions in the fair value of the Kentucky Operations occur, it would reduce future net income and cash flows.

LITIGATION

In the ordinary course of business, AEP is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss if the loss can be estimated. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition. See Note 4 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies for additional information.

Rockport Plant Litigation

In 2013, the Wilmington Trust Company filed suit 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 sought a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. See "Obligations under the New Source Review Litigation Consent Decree" section below for additional information.

After the litigation proceeded at the district court and appellate court, in April 2021, I&M and AEGCo reached an agreement to acquire 100% of the interests in Rockport Plant, Unit 2 for $116 million from certain financial institutions that own the unit through trusts established by Wilmington Trust, the nonaffiliated owner trustee of the ownership interests in the unit, with closing to occur as of the end of the Rockport Plant, Unit 2 lease in December 2022. The agreement is subject to customary closing conditions and as of the closing will result in a final settlement of, and release of claims in, the lease litigation. As a result, in May 2021, at the parties' request, the district court entered a stipulation and order dismissing the case without prejudice to plaintiffs asserting their claims in a re-filed action or a new action. The required regulatory approvals at the IURC and FERC have been obtained that would allow the closing to occur as of the end of the lease in December 2022. Management believes its financial statements appropriately reflect the resolution of the litigation.

Upon the end of the Rockport Unit 2 lease in December 2022, AEGCo's 50% ownership share of Rockport Unit 2 will be billed 100% to I&M under a FERC-approved unit power agreement. In addition, upon the end of the Rockport Unit 2 lease, I&M's 50% ownership share of Rockport Unit 2 and I&M's purchased power from AEGCo related to Rockport Unit 2 will be a merchant resource for I&M until Rockport Unit 2 is retired. A 2021 IURC order approved a settlement agreement addressing the future use of Rockport Unit 2 as a short-term capacity resource through the June 2023 - May 2024 PJM planning year. I&M has a similar proposal pending before the MPSC in I&M's 2022 Michigan Integrated Resource Plan (IRP) filing. If I&M cannot recover its future investment and expenses related to the merchant share of Rockport Unit 2, it could reduce future net income and cash flows and impact financial condition.

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

Four participants in The American Electric Power System Retirement Plan (the Plan) filed a class action complaint in December 2021 in the U.S. District Court for the Southern District of Ohio against AEPSC and the Plan. 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 plaintiffs assert a number of claims on behalf of themselves and the purported class, including 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) AEP failed to provide required notice regarding the changes to the Plan. Among other relief, the Complaint seeks reformation of the Plan to provide additional benefits and the recovery of plan benefits for former employees under such reformed plan. The plaintiffs previously had submitted claims for additional plan benefits to AEP, which were denied. On February 15, 2022, AEPSC and the Plan filed a motion to dismiss the complaint for failure to state a claim. On August 16, 2022, the district court granted the motion to dismiss the complaint without prejudice. The plaintiffs have filed a motion for leave to file an amended complaint. AEP 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 (HB 6)

In 2019, Ohio adopted and implemented HB 6 which benefits OPCo by authorizing rate recovery for certain costs including renewable energy contracts and OVEC's coal-fired generating units. OPCo engaged in lobbying efforts and provided testimony during the legislative process in connection with HB 6. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of an Ohio legislator and associates in connection with an alleged racketeering conspiracy involving the adoption of HB 6. After AEP learned of the criminal allegations against the Ohio legislator and others relating to HB 6, AEP, with assistance from outside advisors, conducted a review of the circumstances surrounding the passage of the bill. Management does not believe that AEP was involved in any wrongful conduct in connection with the passage of HB 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 amended complaint alleged misrepresentations or omissions by AEP regarding: (a) its alleged participation in or connection to public corruption with respect to the passage of HB 6 and (b) its regulatory, legislative, political contribution, 501(c)(4) organization contribution and lobbying activities in Ohio. The complaint sought monetary damages, among other forms of relief. In December 2021, the district court issued an opinion and order dismissing the securities litigation complaint with prejudice, determining that the complaint failed to plead any actionable misrepresentations or omissions. The plaintiffs did not appeal the ruling.

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. In April 2021, a third AEP shareholder filed a similar derivative action in the U.S. District Court for the Southern District of Ohio and a fourth AEP shareholder filed a similar derivative action in the Supreme Court for the State of New York, Nassau County. These 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 derivative complaints together assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets, (c) unjust enrichment, (d) breach of duty for insider trading and (e) contribution for violations of sections 10(b) and 21D of the Securities Exchange Act of 1934; and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The court entered a scheduling order in the New York state court derivative action staying the case other than with respect to briefing the motion to dismiss. AEP filed its motion to dismiss on April 29, 2022. On September 13, 2022, the New York state court granted the motion to dismiss with prejudice and plaintiffs have filed a notice of appeal with the New York appellate court. The two derivative actions pending in federal district court in Ohio have been consolidated and the plaintiffs in the consolidated action filed an amended complaint. AEP filed a motion to dismiss on May 3, 2022 and briefing on the motion to dismiss has been completed. Discovery remains stayed pending the district court's ruling on the motion to dismiss. The plaintiff in the Ohio state court case advised that they no longer agreed to stay the proceedings, therefore, AEP filed a motion to continue the stays of proceedings on May 20, 2022 and the plaintiff filed an amended complaint on June 2, 2022. On June 15, 2022, the Ohio state court entered an order continuing the stays of that case until the resolution of the consolidated derivative actions pending in Ohio federal district court. The defendants will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In March 2021, AEP received a litigation demand letter from counsel representing a purported AEP shareholder. The litigation demand letter is directed to the Board of Directors of AEP and contains factual allegations involving HB 6 that are generally consistent with those in the derivative litigation filed in state and federal court. The letter demands, among other things, that the AEP Board undertake an independent investigation into alleged legal violations by directors and officers, and that, following such investigation, AEP commence a civil action for breaches of fiduciary duty and related claims and take appropriate disciplinary action against those individuals who allegedly harmed the company. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect.

In May 2021, AEP received a subpoena from the SEC's Division of Enforcement seeking various documents, including documents relating to the passage of HB 6 and documents relating to AEP's policies and financial processes and controls. In August 2022, AEP received a second subpoena from the SEC seeking various additional documents relating to its ongoing inquiry. AEP is cooperating fully with the SEC's investigation. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this inquiry will have a material impact on financial condition, results of operations or cash flows.

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. Management is engaged in the development of possible future requirements including the items discussed below. Management believes that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

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

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed below will have a material impact on AEP System generating units. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of September 30, 2022, the AEP System owned generating capacity of approximately 25,300 MWs, of which approximately 11,300 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 $300 million to $500 million through 2026.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in finalizing proposed rules or revising certain existing requirements. The cost estimates will also change based on: (a) potential state rules that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) actual performance of the pollution control technologies installed, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity, (g) compliance with the Federal EPA's revised coal combustion residual rules and (h) other factors. In addition, management continues to evaluate the economic feasibility of environmental investments on regulated and competitive plants.

Obligations under 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. The consent decree has been modified seven times, for various reasons, most recently in 2022. All of the environmental control equipment required by the consent decree has been installed.

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 periodically reviews and revises the NAAQS for criteria pollutants under the CAARevisions tend to increase the stringency of the standards, which in turn may require AEP to make investments in pollution control equipment at existing generating units, or, since most units are already well controlled, to make changes in how units are dispatched and operated. Most recently, the Biden administration has indicated that it is likely to revisit the NAAQS for ozone and PM, which were left unchanged by the prior administration following its review.Management cannot currently predict if any changes to either standard are likely or what such changes may be, but will continue to monitor this issue and any future rulemakings.

Regional Haze

The Federal EPA issued a Clean Air Visibility Rule (CAVR) in 2005, which could require power plants and other facilities to install best available retrofit technology to address regional haze in federal parks and other protected areas. CAVR is implemented by the states, through SIPs, or by the Federal EPA, through FIPs.In 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postponed 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.

Arkansas has an approved regional haze SIP and all of SWEPCo's affected units are in compliance with the relevant requirements.

In Texas, the Federal EPA disapproved portions of the Texas regional haze SIP and 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.Legal challenges to these various rulemakings are pending in both the U.S. Court of Appeals for the Fifth Circuit and the U.S. Court of Appeals for the District of Columbia CircuitManagement 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

CSAPR is 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.

In January 2021, the Federal EPA finalized a revised CSAPR rule, which substantially reduces the ozone season NO_X budgets in 2021-2024. Several utilities and other entities potentially subject to the Federal EPA's NO_X regulations have challenged that final rule in the U.S. Court of Appeals for the District of Columbia Circuit and briefing is underway. Management cannot predict the outcome of that litigation, but believes it can meet the requirements of the rule in the near term, and is evaluating its compliance options for later years, when the budgets are further reduced. In addition, in February 2022, the EPA Administrator signed a proposed FIP for 2015 Ozone NAAQS that would further revise the ozone season NO_X budgets under the existing CSAPR program. AEP is evaluating the proposed changes.

Climate Change, CO_2 Regulation and Energy Policy

In 2019, the Affordable Clean Energy (ACE) rule established a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. 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. In October 2021 the United States Supreme Court granted certiorari and combined four separate petitions seeking review of the D.C. Circuit Court decisions. Oral arguments were held in February 2022 and on June 30, 2022, the United States Supreme Court reversed the D.C. Circuit Court's decision and remanded for further proceedings. The Federal EPA must take some action before anything is required of the utilities as a result of this decision. At a minimum, if the Federal EPA intends to implement the ACE rule, it must conduct additional rulemaking to update its applicable deadlines, which have all passed. Alternatively, the Federal EPA may abandon the ACE rule and proceed to regulate greenhouse gases through a new rule, the scope of which is unknown. The Federal EPA has previously announced it expects to propose a new rule by spring of 2023. Management is unable 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 October 2022, 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. AEP adjusted its near-term carbon dioxide emission reduction target from a 2000 baseline to a 2005 baseline, upgraded its 80% reduction by 2030 target to include full Scope 1 emissions and accelerated its net-zero goal by five years to 2045. AEP's total Scope 1 GHG emissions in 2021 were approximately 56 million metric tons CO_2e, approximately a 63% reduction from AEP's 2005 Scope 1 GHG 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 have led to the announcement of early plant closures and could force AEP to close additional coal-fired generation facilities earlier than their estimated 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 Rule

The Federal EPA's CCR rule regulates 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 and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers.

In 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)			
AEGCo	Rockport Plant, Unit 1	655	$	222.2		2028
APCo	Amos Plant	2,930		2,123.6		2040
APCo	Mountaineer Plant	1,320		979.0		2040
I&M	Rockport Plant, Unit 1	655		462.9	(b)	2028
KPCo	Mitchell Plant	780		575.6		2040
SWEPCo	Flint Creek Plant	258		263.6		2038
WPCo	Mitchell Plant	780		603.6		2040

(a) Net book value before cost of removal including CWIP and inventory.
(b) Amount includes a $153 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 January 2022, the Federal EPA began responding to applications for extension requests and has proposed to deny several extension requests based on allegations that the utilities that received such responses are not in compliance with the CCR Rule.The Federal EPA's allegations of noncompliance rely on new interpretations of the CCR Rule requirements.The actions of the Federal EPA have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit as unlawful rulemaking that revises the existing CCR Rule requirements without proper notice and without opportunity for comment. Management is unable to predict the outcome of that litigation. On July 12, 2022, the Federal EPA proposed conditional approval of the pending extension request for the Mountaineer Plant. The Federal EPA has not yet proposed any action on the other pending extension requests submitted by AEP; however, statements made by the Federal EPA in proposed denials of extension requests submitted by other utilities indicate that there is a risk that the Federal EPA may similarly conclude that AEP is not eligible for an extension of time to cease use of those CCR impoundments and/or that one or more of AEP's facilities is not in compliance with the CCR RuleIf that occurs, AEP may incur material additional costs to change its plans for complying with the CCR Rule, including the potential to have to temporarily cease operation of one or more facilities until an acceptable compliance alternative can be implemented. Such temporary cessation of operation could materially impact the cost of serving customers of the affected utility. Further, actions by the Federal EPA could require AEP to remove coal ash from CCR units that have already been closed in accordance with state law programs or could require AEP to incur costs related to CCR units at various active and legacy facilities.

Closure and post-closure costs have been included in ARO in accordance with the requirements in the Federal EPA's final CCR 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. AEP may incur significant additional costs complying with the Federal EPA's CCR Rule including costs to upgrade or close and replace surface impoundments and landfills used to manage CCR and to conduct any required remedial actions including removal of coal ash.If additional costs are incurred and AEP is unable to obtain cost recovery, it would reduce future net income and cash flows and impact financial condition. Management will continue to participate in rulemaking activities and make adjustments based on new federal and state requirements affecting its ash disposal units.

The second option to obtain an extension of the April 11, 2021 deadline to cease operation of unlined impoundments allows a generating facility to continue operating its existing impoundments without developing alternative CCR disposal, provided the facility commits to cease combustion of coal by a date certain. Under this option, a generating facility would have until October 17, 2023 to cease coal-fired operations 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 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 Plant	580	$ 65.0	$ 150.7	2023 (b)
SWEPCo	Welsh Plant, Units 1 and 3	1,053	432.3	75.7	2028 (c)(d)

(a) Net book value including CWIP excluding cost of removal and materials and supplies.
(b) Pirkey 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.

To date, the Federal EPA has not taken any action on these pending extension requests. Under the second option above, AEP may need to recover remaining depreciation and estimated closure costs associated with these 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 these plants in a timely manner, it would reduce future net income and cash flows and impact financial condition.

Clean Water Act Regulations

The Federal EPA's ELG rule for generating facilities establishes limits for FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater, which are to be implemented through each facility's wastewater discharge permit. A revision to the ELG rule, published in October 2020, 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. For affected facilities that must install additional technologies to meet the ELG rule limits, permit modifications were filed in January 2021 that reflect the outcome of that assessment. AEP continues to work with state agencies to finalize permit terms and conditions. Other facilities opted to file Notices of Planned Participation (NOPP), pursuant to which the facilities are not required to install additional controls to meet ELG limits provided they make commitments to cease coal combustion by a date certain. The Federal EPA has announced its intention to reconsider the 2020 rule and to further revise limits applicable to discharges of landfill and impoundment leachate. A proposed rule is expected in late 2022 or early 2023. Management cannot predict whether the Federal EPA will actually finalize further revisions or what such revisions might be, but will continue to monitor this issue and will participate in further rulemaking activities as they arise.

In August 2021, the Federal EPA and the Army Corps of Engineers announced their plan to reconsider and revise the Navigable Waters Protection Rule, which defines "waters of the United States" under the Clean Water Act. Shortly thereafter, the United States District Court for the District of Arizona vacated and remanded the Navigable Waters Protection Rule, which had the effect of reinstating the prior, much broader, version of the rule. Because the scope of waters subject to the Federal EPA and Army Corps of Engineers jurisdictions is broader under the prior rule, permitting decisions made in recent years are subject to reevaluation; permits may now be necessary where none were previously required, and issued permits may need to be reopened to impose additional obligations. In December 2021, the Federal EPA proposed a rule that would roll back the definition of "waters of the United States" to the pre-2015 definition. The Federal EPA also announced that it would be considering further changes through a future rulemaking, which would build upon the foundation of the proposed rule. Management will continue to monitor rulemaking on this issue.

In October 2022, the U.S. Supreme Court heard an appeal related to the scope of "waters of the United States," specifically which wetlands can be regulated as waters of the United States. Management cannot predict the outcome of that litigation.

CCR and ELG Compliance Plan Filings

Mitchell Plant (Applies to AEP)

KPCo and WPCo each own a 50% interest in the Mitchell PlantAs of September 30, 2022, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $576 million. 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 CCR and ELG compliance plans an seek recovery of the estimated $132 million investment for the Mitchell Plant that would allow the plant to continue operating beyond 2028. Within those requests, WPCo and KPCo also filed a $25 million alternative to implement only the CCR-related investments with the WVPSC and KPSC respectively, which would allow the Mitchell Plant to continue operating only through 2028.

In July 2021, the KPSC issued an order approving the CCR only alternative and rejecting the full CCR and ELG compliance plan. In May 2022, the KPSC approved recovery of the Kentucky jurisdictional share of ELG costs incurred at the Mitchell Plant prior to July 15, 2021.

In August 2021, the WVPSC approved the full CCR and ELG compliance plan for the WPCo share of the Mitchell Plant. In September 2021, WPC submitted a filing with the WVPSC to reopen the CCR/ELG case that was approved by the WVPSC in August 2021. Due to the rejection by th KPSC of the KPCo share of the ELG investments, WPCo requested the WVPSC consider approving the construction and recovery of all ELG cos at the plant. In October 2021, the WVPSC affirmed its August 2021 order approving the construction of CCR/ELG investments and directed WPC to proceed with CCR/ELG compliance plans that would allow the plant to continue operating beyond 2028.The WVPSC also ordered that WPCo will be given the opportunity to recover, from its customers, the ELG and new capital and operating costs arising solely from the WVPSC's directive to operate the plant beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred.The WVPSC's order further states that unless KPCo pays for its share of costs for ELG improvements and costs necessary to continue operations beyond 2028, the benefit of the capacity and energy made possible by those improvements and operating Mitchell Plant beyond 2028 should benefit only West Virginia jurisdictional customers who have shared in paying for those costs.

Amos and Mountaineer Plants (Applies to AEP and APCo)

In December 2020, APCo submitted filings with the Virginia SCC and WVPSC requesting regulatory approvals necessary to recover the estimated $240 million investment needed to implement CCR and ELG compliance for the Amos and Mountaineer plants.In August 2021, the Virginia SCC issued an order approving recovery of CCR-related operation and maintenance expenses and investments at the Amos and Mountaineer Plants through an active rider. The order also denied APCo's request to recover the cost of ELG investments and denied recovery of previously incurred ELG costs, but did not preclude APCo from refiling for approval.In March 2022, APCo refiled for approval to recover the cost of the ELG investments and previously incurred ELG costs. Intervenor testimony was submitted in August 2022 recommending the denial of ELG cost recovery. In October 2022, a Virginia Hearing Examiner recommended that the Virginia SCC approve recovery of APCo's requested ELG investment costs at Amos and Mountaineer Plants. Management expects to receive an order from the Virginia SCC in the fourth quarter of 2022.

Also in August 2021, the WVPSC approved the request to construct CCR/ELG investments at the Amos and Mountaineer Plants and approved recovery of the West Virginia jurisdictional share of these costs through an active rider. In October 2021, due to the Virginia SCC previously rejecting those ELG investments, the WVPSC issued an order directing APCo to proceed with CCR/ELG compliance plans that would allow the plants to continue operating beyond 2028. The WVPSC also ordered that APCo will be given the opportunity to recover, from West Virginia customers, the ELG and new capital and operating costs arising solely from the WVPSC's directive to operate the plants beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred. The October 2021 order further states that unless the Virginia jurisdictional customers of APCo pay for their share of costs for ELG improvements and costs necessary to continue operations beyond 2028, the benefit of the capacity and energy made possible by those improvements and operating the Amos and Mountaineer Plants beyond 2028 should benefit only West Virginia and FERC jurisdictional customers who have shared in paying for those costs.

APCo expects the total Amos and Mountaineer Plant ELG investment, excluding AFUDC, to be approximately $162 million. As of September 30, 2022, APCo's Virginia jurisdictional share of the net book value, before cost of removal including CWIP and inventory, of the Amos and Mountaineer Plants was approximately $1.5 billion and APCo's Virginia jurisdictional share of its ELG investment balance in CWIP for these plants was $62 million.

If any of the ELG costs are not approved for recovery and/or the retirement dates of the Amos and Mountaineer Plants are accelerated to 2028 without commensurate cost recovery, it would reduce future net income and cash flows and impact financial condition.

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, remediation 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.

Previously, management retired or announced early closure plans for Welsh Unit 2, Dolet Hills Power Station and Northeastern Plant Unit 3.

The table below summarizes the net book value, as of September 30, 2022, of generating facilities retired or planned for early retirement in advance of the retirement date currently authorized for ratemaking purposes:

Company	Plant	Net Investment (a)	Accelerated Depreciation Regulatory Asset	Actual/Projected Retirement Date	Current Authorized Recovery Period	Annual Depreciation (b)
		(in millions)				(in millions)
PSO	Northeastern Plant, Unit 3	$ 143.7	$ 141.4	2026	(c)	$ 14.9
SWEPCo	Dolet Hills Power Station	—	54.7	2021	(d)	—
SWEPCo	Pirkey Plant	65.0	150.7	2023	(e)	12.5
SWEPCo	Welsh Plant, Units 1 and 3	432.3	75.7	2028 (f)	(g)	39.8
SWEPCo	Welsh Plant, Unit 2	—	35.2	2016	(h)	—

(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) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(d) Dolet Hills Power Station is currently being recovered through 2026 in the Louisiana jurisdiction and through 2046 in the Texas jurisdiction. In December 2021, the PUCT authorized the recovery of SWEPCo's Texas jurisdictional share of the Dolet Hills Power Station through 2046 without providing a return on the investment which resulted in a disallowance of $12 million. In May 2022, the APSC authorized the recovery of SWEPCo's Arkansas jurisdictional share of the Dolet Hills Power Station through 2027 without providing a return on investment, which resulted in an immaterial disallowance in the second quarter of 2022. See Note 4 - Rate Matters for additional information.
(e) Pirkey Plant is currently being recovered through 2025 in the Louisiana jurisdiction and through 2045 in the Arkansas and Texas jurisdictions.
(f) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028.
(g) 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.
(h) 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 is 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 ROE.
- Development, construction and operation of transmission facilities through investments in AEP's transmission-only joint ventures. These investments have PUCT-approved or FERC-approved ROE.

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 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, as presented in the Registrants' statements of income as applicable. Under the various state utility rate making processes, these expenses are generally reimbursable directly from and billed to customers. As a result, they do not typically impact Operating Income or Earnings Attributable to AEP Common Shareholders.Management believes that Gross Margin provides a useful measure for investors and other financial statement users to analyze AEP's financial performance in that it excludes the effect on Total Revenues caused by volatility in these expenses. Operating Income, which is presented in accordance with GAAP in AEP's statements of income, is the most directly comparable GAAP financial measure to the presentation of Gross Margin. AEP's definition of Gross Margin may not be directly comparable to similarly titled financial measures used by other companies.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Vertically Integrated Utilities	$ 476.9	$ 437.7	$ 1,076.3	$ 936.3
Transmission and Distribution Utilities	165.5	155.9	483.1	424.0
AEP Transmission Holdco	170.5	166.8	485.4	507.5
Generation & Marketing	97.5	100.7	284.3	189.7
Corporate and Other	(226.7)	(65.1)	(406.2)	(108.3)
Earnings Attributable to AEP Common Shareholders	$ 683.7	$ 796.0	$ 1,922.9	$ 1,949.2

AEP CONSOLIDATED

Third Quarter of 2022 Compared to Third Quarter of 2021

Earnings Attributable to AEP Common Shareholders decreased from $796 million in 2021 to $684 million in 2022 primarily due to:

- A loss on the expected sale of the Kentucky Operations.
- An increase in depreciation expense due to continued investment.

This decrease was partially offset by:

- Favorable rate proceedings in AEP's various jurisdictions.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Earnings Attributable to AEP Common Shareholders decreased from $1,949 million in 2021 to $1,923 million in 2022 primarily due to:

- A loss on the expected sale of the Kentucky Operations.
- An impairment of AEP's equity investment in Flat Ridge 2.
- An increase in depreciation expense due to continued investment.

These decreases were partially offset by:

- A gain on the sale of mineral rights.
- Favorable rate proceedings in AEP's various jurisdictions.
- Increased sales volumes.
- Favorable mark-to-market economic hedge activity driven by higher commodity prices.

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

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
	(in millions)			
Revenues	$ 3,226.3	$ 2,759.3	$ 8,562.2	$ 7,557.2
Fuel and Purchased Electricity	1,191.9	855.3	2,895.8	2,364.7
Gross Margin	2,034.4	1,904.0	5,666.4	5,192.5
Other Operation and Maintenance	834.0	796.9	2,383.1	2,240.6
Asset Impairments and Other Related Charges	24.9	—	24.9	—
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—	(37.0)	—
Depreciation and Amortization	520.6	436.3	1,525.0	1,302.2
Taxes Other Than Income Taxes	130.1	124.1	383.9	375.6
Operating Income	561.8	546.7	1,386.5	1,274.1
Other Income	9.0	4.1	24.9	9.9
Allowance for Equity Funds Used During Construction	6.0	9.6	20.4	30.3
Non-Service Cost Components of Net Periodic Benefit Cost	27.4	17.0	82.4	51.0
Interest Expense	(168.8)	(144.3)	(477.1)	(425.5)
Income Before Income Tax Expense (Benefit) and Equity Earnings	435.4	433.1	1,037.1	939.8
Income Tax Expense (Benefit)	(41.2)	(4.6)	(41.3)	3.4
Equity Earnings of Unconsolidated Subsidiary	0.3	1.0	1.0	2.5
Net Income	476.9	438.7	1,079.4	938.9
Net Income Attributable to Noncontrolling Interests	—	1.0	3.1	2.6
Earnings Attributable to AEP Common Shareholders	$ 476.9	$ 437.7	$ 1,076.3	$ 936.3

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
	(in millions of KWhs)			
Retail:				
Residential	9,115	9,119	25,379	25,125
Commercial	6,640	6,468	18,069	17,396
Industrial	8,862	8,485	25,930	24,798
Miscellaneous	623	604	1,745	1,672
Total Retail	25,240	24,676	71,123	68,991
Wholesale (a)	4,254	5,713	12,388	14,842
Total KWhs	29,494	30,389	83,511	83,833

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

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in degree days)			
Eastern Region				
Actual – Heating (a)	8	1	1,750	1,710
Normal – Heating (b)	4	4	1,748	1,742
Actual – Cooling (c)	783	847	1,178	1,209
Normal – Cooling (b)	745	744	1,082	1,087
Western Region				
Actual – Heating (a)	—	—	930	993
Normal – Heating (b)	—	1	906	901
Actual – Cooling (c)	1,653	1,485	2,558	2,163
Normal – Cooling (b)	1,413	1,410	2,134	2,137

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

Third Quarter of 2022 Compared to Third Quarter of 2021

Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Third Quarter of 2021	$	437.7
Changes in Gross Margin:		
Retail Margins		92.7
Margins from Off-system Sales		8.3
Transmission Revenues		21.9
Other Revenues		7.5
Total Change in Gross Margin		130.4
Changes in Expenses and Other:		
Other Operation and Maintenance		(37.1)
Asset Impairments and Other Related Charges		(24.9)
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset		37.0
Depreciation and Amortization		(84.3)
Taxes Other Than Income Taxes		(6.0)
Other Income		4.9
Allowance for Equity Funds Used During Construction		(3.6)
Non-Service Cost Components of Net Periodic Pension Cost		10.4
Interest Expense		(24.5)
Total Change in Expenses and Other		(128.1)
Income Tax Benefit		36.6
Equity Earnings of Unconsolidated Subsidiary		(0.7)
Net Income Attributable to Noncontrolling Interests		1.0
Third Quarter of 2022	$	476.9

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

- **Retail Margins** increased $93 million primarily due to the following:
  - A $47 million increase at PSO due to a $26 million increase in base rate revenues and a $21 million increase in rider revenues. These increases were partially offset in other expense items below.
  - A $40 million increase at SWEPCo primarily due to base rate revenue increases in Texas and Arkansas and an increase in rider revenues in all jurisdictions. These increases were partially offset in other expense items below.
  - A $22 million increase at APCo and WPCo due to an increase in rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.
  - A $15 million increase at I&M primarily due to an increase in rider revenues. This increase was partially offset in other expense items below.
  - An $11 million increase in weather-related usage primarily in the residential class.

  These increases were partially offset by:
  - A $47 million decrease at PSO and SWEPCo resulting from the NCWF PTC benefits provided to customers through fuel claus mechanisms. This decrease was partially offset in Income Tax Benefit below.

- A $10 million decrease in weather-normalized retail margins primarily in the residential class.
- **Margins from Off-system Sales** increased $8 million primarily due to the following:
  - A $7 million increase due to an increase in Turk Plant merchant sales at SWEPCo.
  - A $3 million increase at APCo primarily due to increased generation and strong market pricing.
- **Transmission Revenues** increased $22 million primarily due to continued investment in transmission assets and increased load.
- **Other Revenues** increased $8 million primarily due to an increase in pole attachment rental revenue.

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

- **Other Operation and Maintenance** expenses increased $37 million primarily due to the following:
  - A $15 million increase in PJM transmission services. This increase was partially offset in Retail Margins above.
  - A $13 million increase in SPP transmission services. This increase was partially offset in Retail Margins above.
  - An $11 million increase due to the expensing of cancelled capital projects.
  - An $11 million increase in generation expenses primarily due to plant outages and maintenance at APCo and I&M.
  - A $6 million increase in storm restoration expenses.
  - A $5 million increase in distribution system improvements across multiple operating companies.
  - A $5 million increase in Energy Efficiency/Demand Response expenses. This increase was partially offset in Retail Margins above.

  These increases were partially offset by:
  - A $36 million decrease due to the modification of the Rockport Plant, Unit 2 lease which resulted in a change in lease classification from an operating lease to a finance lease in December 2021 at AEGCo and I&M. This decrease is offset in Depreciation and Amortization expense below.
- **Asset Impairments and Other Related Charges** increased $25 million at APCo due to the write-off of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to the 2017-2019 Virginia Triennial review.
- **Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset** increased $37 million at APCo due to the establishment of a regulatory asset based on an August 2022 Virginia Supreme Court opinion and resulting under-earning during the 2017-2019 Triennial Review.
- **Depreciation and Amortization** expenses increased $84 million primarily due to the following:
  - A $45 million increase due to a higher depreciable base primarily at APCo, I&M, PSO and SWEPCo and the implementation of new rates and the timing of refunds to customers under rate rider mechanisms at PSO and in Arkansas and Texas for SWEPCo.The increase due to implementation of new rates and the timing of refunds to customers under rate rider mechanisms at PSO was partially offset in Retail Margins above.
  - A $39 million increase due to the modification of the Rockport Plant, Unit 2 lease which resulted in a change in lease classification from an operating lease to a finance lease in December 2021 at AEGCo and I&M.This increase was partially offset in Other Operation and Maintenance expenses above.
- **Taxes Other Than Income Taxes** increased $6 million due to the following:
  - A $9 million increase at PSO and SWEPCo primarily due to increased property taxes and a new infrastructure fee at PSO implemented by the City of Tulsa in March 2022. This increase was partially offset in Retail Margins above.

  This increase was partially offset by:
  - A $5 million decrease at I&M primarily due to the repeal of the Indiana Utility Receipts Tax in July 2022.This decrease was partially offset in Retail Margins above.
- **Other Income** increased $5 million at PSO primarily due to carrying charges on regulatory assets resulting from the February 2021 severe winter weather event.
- **Allowance for Equity Funds Used During Construction** decreased $4 million primarily due to a decrease in AFUDC equity rates at APCo.

- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $10 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $25 million primarily due to higher long-term debt balances at APCo, PSO and SWEPCo, increased Advances from Affiliates at SWEPCo and higher interest rates at APCo.
- **Income Tax Benefit** increased $37 million primarily due to an increase in PTCs partially offset by a decrease in amortization of Excess ADIT. These items were partially offset in Retail Margins above.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Nine Months Ended September 30, 2021	$	936.3
Changes in Gross Margin:		
Retail Margins		404.6
Margins from Off-system Sales		(18.9)
Transmission Revenues		66.8
Other Revenues		21.4
Total Change in Gross Margin		473.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(142.5)
Asset Impairments and Other Related Charges		(24.9)
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset		37.0
Depreciation and Amortization		(222.8)
Taxes Other Than Income Taxes		(8.3)
Other Income		15.0
Allowance for Equity Funds Used During Construction		(9.9)
Non-Service Cost Components of Net Periodic Pension Cost		31.4
Interest Expense		(51.6)
Total Change in Expenses and Other		(376.6)
Income Tax Expense		44.7
Equity Earnings of Unconsolidated Subsidiary		(1.5)
Net Income Attributable to Noncontrolling Interests		(0.5)
Nine Months Ended September 30, 2022	$	1,076.3

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

- **Retail Margins** increased $405 million primarily due to the following:
  - A $111 million increase at APCo and WPCo due to an increase in rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.
  - A $95 million increase at PSO due to a $51 million increase in base rate revenues and a $44 million increase in rider revenues. These increases were partially offset in other expense items below.
  - An $80 million increase at SWEPCo primarily due to base rate revenue increases in Texas and Arkansas and an increase in rider revenues in all retail jurisdictions. These increases were partially offset in other expense items below.
  - A $43 million increase at I&M due to an increase in rider revenues offset by lower wholesale true-ups. This increase was partially offset in other expense items below.
  - A $41 million increase in weather-related usage primarily in the residential class.
  - A $35 million increase in weather-normalized retail margins primarily in the commercial class.

These increases were partially offset by:

- A $62 million decrease at PSO and SWEPCo resulting from the NCWF PTC benefits provided to customers through fuel claus mechanisms. This decrease was partially offset in Income Tax Expense below.

- **Margins from Off-system Sales** decreased $19 million primarily due to the following:
  - A $10 million decrease due to Turk Plant merchant sales as a result of the February 2021 severe winter weather event at SWEPCo.
  - A $7 million decrease at KPCo due to a change in the OSS sharing arrangement.
- **Transmission Revenues** increased $67 million primarily due to the following:
  - A $47 million increase in continued investment in transmission assets and increased load.
  - A $20 million increase in formula rate true-up activity.
- **Other Revenues** increased $21 million primarily due to the following:
  - A $7 million increase at APCo primarily due to business development revenue. This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $6 million increase at I&M primarily due to a gain on sale of allowances and economic hedging activities. The gain on the sale of allowances was partially offset in Retail Margins above.
  - A $3 million increase at KPCo primarily due to rental revenue from pole attachments, a gain on the sale of allowances and business development revenue.

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

- **Other Operation and Maintenance** expenses increased $143 million primarily due to the following:
  - A $96 million increase in PJM transmission services. This increase was partially offset in Retail Margins above.
  - A $62 million increase in generation expenses primarily due to outages and maintenance at APCo, I&M and PSO.
  - A $25 million increase in SPP transmission services. This increase was partially offset in Retail Margins above.
  - A $16 million increase in storm restoration expenses.
  - A $12 million increase in Energy Efficiency/Demand Response expenses. This increase was partially offset in Retail Margins above.
  - An $11 million increase in employee-related expenses.
  - An $11 million increase due to the expensing of cancelled capital projects.

  These increases were partially offset by:
  - A $108 million decrease due to the modification of the Rockport Plant, Unit 2 lease which resulted in a change in lease classification from an operating lease to a finance lease in December 2021 at AEGCo and I&M. This decrease is offset in Depreciation and Amortization expense below.
- **Asset Impairments and Other Related Charges** increased $25 million at APCo due to the write-off of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to the 2017-2019 Virginia Triennial review.
- **Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset** increased $37 million at APCo due to the establishment of a regulatory asset based on an August 2022 Virginia Supreme Court opinion and resulting under-earning during the 2017-2019 Triennial Review.
- **Depreciation and Amortization** expenses increased $223 million primarily due to the following:
  - A $117 million increase due to the modification of the Rockport Plant, Unit 2 lease which resulted in a change in lease classification from an operating lease to a finance lease in December 2021 at AEGCo and I&M.This increase was partially offset in Other Operation and Maintenance expenses above.
  - A $106 million increase due to a higher depreciable base primarily at APCo, I&M, PSO and SWEPCo, the implementation of new rates an the timing of refunds to customers under rate rider mechanisms at PSO and in Arkansas and Texas for SWEPCo.The increase due to implementation of new rates and the timing of refunds to customers under rate rider mechanisms at PSO was partially offset in Retail Margins above.

- **Taxes Other Than Income Taxes** increased $8 million primarily due to the following:
  - A $13 million increase at PSO and SWEPCo primarily due to increased property taxes and a new infrastructure fee at PSO implemented by the City of Tulsa in March 2022. This increase was partially offset in Retail Margins above.
  - A $4 million increase at APCo primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.

  These increases were partially offset by:
  - An $8 million decrease at I&M primarily due to the repeal of the Indiana Utility Receipts Tax in July 2022.This decrease was partially offset in Retail Margins above.
- **Other Income** increased $15 million primarily due to carrying charges on regulatory assets resulting from the February 2021 severe winter weather event at PSO and SWEPCo.
- **Allowance for Equity Funds Used During Construction** decreased $10 million primarily due to a decrease in AFUDC equity rates primarily at APCo.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $31 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $52 million primarily due to higher long-term debt balances at APCo, PSO and SWEPCo, increased Advances from Affiliates at SWEPCo, higher interest rates at APCo and a debt issuance at I&M in April 2021.
- **Income Tax Expense** decreased $45 million primarily due to the following:
  - An $81 million increase in PTCs. This increase was partially offset in Retail Margins above.
  - A $7 million decrease in state taxes.

  These decreases were partially offset by:
  - A $19 million increase due to an increase in pretax book income.
  - A $14 million decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT was partially offset in Gross Margin above.
  - A $14 million decrease in Parent Company Loss Benefit.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
	(in millions)			
Revenues	$ 1,530.2	$ 1,200.3	$ 4,078.6	$ 3,391.8
Purchased Electricity	399.5	188.1	884.8	561.6
Gross Margin	1,130.7	1,012.2	3,193.8	2,830.2
Other Operation and Maintenance	503.6	442.6	1,373.2	1,168.6
Depreciation and Amortization	188.3	164.6	559.5	515.8
Taxes Other Than Income Taxes	176.7	167.5	504.9	483.5
Operating Income	262.1	237.5	756.2	662.3
Other Income	1.4	0.5	3.7	2.2
Allowance for Equity Funds Used During Construction	9.3	11.3	23.6	24.3
Non-Service Cost Components of Net Periodic Benefit Cost	11.9	7.3	35.7	21.8
Interest Expense	(85.4)	(77.3)	(242.2)	(228.8)
Income Before Income Tax Expense and Equity Earnings	199.3	179.3	577.0	481.8
Income Tax Expense	33.8	23.4	94.7	57.8
Equity Earnings of Unconsolidated Subsidiary	—	—	0.8	—
Net Income	165.5	155.9	483.1	424.0
Net Income Attributable to Noncontrolling Interests	—	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 165.5	$ 155.9	$ 483.1	$ 424.0

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
	(in millions of KWhs)			
Retail:				
Residential	8,033	8,093	21,599	21,082
Commercial	7,538	7,125	20,478	19,189
Industrial	6,554	6,048	19,131	17,667
Miscellaneous	210	207	578	558
Total Retail (a)	22,335	21,473	61,786	58,496
Wholesale (b)	587	644	1,723	1,692
Total KWhs	22,922	22,117	63,509	60,188

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in degree days)			
Eastern Region				
Actual – Heating (a)	8	1	2,078	1,993
Normal – Heating (b)	5	5	2,077	2,071
Actual – Cooling (c)	755	787	1,115	1,148
Normal – Cooling (b)	688	689	989	996
Western Region				
Actual – Heating (a)	—	—	278	319
Normal – Heating (b)	—	—	193	188
Actual – Cooling (d)	1,478	1,308	2,701	2,278
Normal – Cooling (b)	1,382	1,379	2,433	2,436

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

Third Quarter of 2022 Compared to Third Quarter of 2021

Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Third Quarter of 2021	$	155.9
Changes in Gross Margin:		
Retail Margins		74.9
Margins from Off-system Sales		21.8
Transmission Revenues		11.4
Other Revenues		10.4
Total Change in Gross Margin		118.5
Changes in Expenses and Other:		
Other Operation and Maintenance		(61.0)
Depreciation and Amortization		(23.7)
Taxes Other Than Income Taxes		(9.2)
Other Income		0.9
Allowance for Equity Funds Used During Construction		(2.0)
Non-Service Cost Components of Net Periodic Benefit Cost		4.6
Interest Expense		(8.1)
Total Change in Expenses and Other		(98.5)
Income Tax Expense		(10.4)
Third Quarter of 2022	$	165.5

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

- **Retail Margins** increased $75 million primarily due to the following:
  - A $31 million increase due to interim rate increases driven by increased distribution and transmission investment in Texas.
  - A $21 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $7 million increase in weather-related usage in Texas primarily due to a 13% increase in cooling degree days.
  - A $6 million increase in revenue from rate riders in Texas. This increase was partially offset in other expense items below.
  - A $4 million increase in weather-related usage in Ohio primarily due to the end of decoupling.
- **Margins from Off-system Sales** increased $22 million primarily due to the following:
  - A $17 million increase in off-system sales at OVEC in Ohio due to higher market prices.This increase was offset in Retail Margins above and Other Revenues below.
  - A $5 million increase in deferrals of OVEC costs in Ohio. This increase was offset in Retail Margins above and Other Revenues below.
- **Transmission Revenues** increased $11 million primarily due to interim rate increases driven by increased transmission investment in Texas.

- **Other Revenues** increased $10 million primarily due to the following:
  - A $19 million increase in securitization revenues due to AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset in Depreciation and Amortization expenses and Interest Expense below.

  This increase was partially offset by:
  - A $13 million decrease due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs in OhioThis decrease was offset in Retail Margins and Margins from Off-system Sales above.

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

- **Other Operation and Maintenance** expenses increased $61 million primarily due to the following:
  - A $21 million increase in ERCOT transmission expenses.This increase was partially offset in Retail Margins and Transmission Revenues above.
  - A $14 million increase in transmission expenses in Ohio primarily due to an increase in recoverable PJM expenses.This increase was offset in Retail Margins above.
  - A $6 million increase in distribution-related expenses in Texas.
  - A $5 million increase in remitted Universal Service Fund 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 $5 million increase in recoverable distribution expenses in Ohio primarily related to vegetation management. This increase was offset in Retail Margins above.
- **Depreciation and Amortization** expenses increased $24 million primarily due to the following:
  - A $19 million increase in securitization amortizations primarily due to prior year AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset in Other Revenues above.
  - A $6 million increase due to a higher depreciable base of transmission and distribution assets in Texas.
  - A $4 million increase in recoverable advanced metering system depreciable expenses in Texas.

  These increases were partially offset by:
  - A $6 million decrease in recoverable Distribution Investment Rider depreciable expenses in Ohio.This decrease was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $9 million primarily due to property taxes as a result of increased distribution and transmission investment and higher tax rates.
- **Non-Service Cost Components of Net Periodic Benefit Cost**decreased $5 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $8 million primarily due to the following:
  - An $11 million increase in Texas primarily due to higher long-term debt balances and higher interest rates.

  This increase was partially offset by:
  - A $3 million decrease in Ohio primarily due to the retirement of a higher rate bond, partially offset by the issuance of a lower rate bond in 2021.
- **Income Tax Expense** increased $10 million primarily due to an increase in pretax book income and a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT was offset in Gross Margin above.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Nine Months Ended September 30, 2021	$	424.0
Changes in Gross Margin:		
Retail Margins		290.0
Margins from Off-system Sales		47.8
Transmission Revenues		50.0
Other Revenues		(24.2)
Total Change in Gross Margin		363.6
Changes in Expenses and Other:		
Other Operation and Maintenance		(204.6)
Depreciation and Amortization		(43.7)
Taxes Other Than Income Taxes		(21.4)
Other Income		1.5
Allowance for Equity Funds Used During Construction		(0.7)
Non-Service Cost Components of Net Periodic Benefit Cost		13.9
Interest Expense		(13.4)
Total Change in Expenses and Other		(268.4)
Income Tax Expense		(36.9)
Equity Earnings of Unconsolidated Subsidiary		0.8
Nine Months Ended September 30, 2022	$	483.1

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

- **Retail Margins** increased $290 million primarily due to the following:
  - An $85 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $70 million increase due to interim rate increases driven by increased distribution and transmission investment in Texas.
  - A $31 million increase due to prior year refunds of Excess ADIT to customers in Texas. This increase was offset in Income Tax Expense below.
  - A $28 million increase in weather-normalized margins primarily from the commercial class.
  - A $25 million increase related to various rider revenues in Ohio. This increase was partially offset in Margins from Off-system Sales, Other Revenues and other expense items below.
  - A $20 million increase in revenue from rate riders in Texas. This increase was partially offset in other expense items below.
  - A $15 million increase in weather-related usage in Texas primarily due to a 19% increase in cooling degree days, partially offset by a 13% decrease in heating degree days.
  - An $8 million increase in weather-related usage in Ohio primarily due to the end of decoupling.
- **Margins from Off-system Sales** increased $48 million primarily due to the following:
  - A $54 million increase in off-system sales at OVEC in Ohio due to higher market prices and volume.This increase was offset in Retail Margins above and Other Revenues below.

This increase was partially offset by:

- A $6 million decrease in deferrals of OVEC costs in Ohio. This decrease was offset in Retail Margins above and Other Revenues below.

- **Transmission Revenues** increased $50 million primarily due to the following:
  - A $46 million increase due to interim rate increases driven by increased transmission investment in Texas.
  - A $7 million increase due to prior year refunds to customers associated with the most recent base rate case in Texas. This increase was offset in Other Revenues below.
  - A $7 million increase due to continued investment in transmission assets in Ohio.

  These increases were partially offset by:
  - An $11 million decrease due to transmission formula rate true-up activity in Ohio.
- **Other Revenues** decreased $24 million primarily due to the following:
  - A $29 million decrease primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs in Ohio. This decrease was offset in Retail Margins and Margins from Off-system Sales above.
  - A $12 million decrease due to prior year refunds to customers associated with the most recent base rate case in Texas. This decrease was partially offset in Retail Margins and Transmission Revenues above.
  - A $5 million decrease in energy efficiency revenues in Texas.

  These decreases were partially offset by:
  - A $20 million increase in securitization revenues due to AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset in Depreciation and Amortization expenses and Interest Expense below.

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

- **Other Operation and Maintenance** expenses increased $205 million primarily due to the following:
  - A $67 million increase in transmission expenses in Ohio primarily due to the following:
    - A $67 million increase in recoverable PJM expenses. This increase was offset in Retail Margins above.
    - A $6 million increase in transmission vegetation management expenses.

    These increases were partially offset by:
    - A $10 million decrease in transmission formula rate true-up activity.
  - A $46 million increase in ERCOT transmission expenses.This increase was partially offset in Retail Margins and Transmission Revenues above.
  - A $20 million increase in employee-related expenses.
  - A $19 million increase in bad debt-related expenses, including $8 million in 2022 due to Bad Debt Rider over-recovery in Ohio.This increase was offset in Retail Margins above.
  - A $15 million increase in recoverable distribution expenses in Ohio primarily related to vegetation management. This increase was offset in Retail Margins above.
  - A $14 million increase in remitted Universal Services Fund 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 $13 million increase in distribution-related expenses in Texas.
- **Depreciation and Amortization** expenses increased $44 million primarily due to the following:
  - A $24 million increase due to a higher depreciable base and amortizations of transmission and distribution assets in Texas.
  - A $19 million increase in securitization amortizations primarily due to prior year AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset in Other Revenues above.
  - An $11 million increase in recoverable advanced metering system depreciable expenses in Texas.

  These increases were partially offset by:
  - A $6 million decrease in recoverable smart grid depreciable expenses in Ohio. This decrease was offset in Retail Margins above.

- A $6 million decrease in recoverable Distribution Investment Rider depreciable expenses in Ohio.This decrease was offset in Retail Margins above.

- **Taxes Other Than Income Taxes** increased $21 million primarily due to increased property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $14 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $13 million primarily due to the following:
  - A $21 million increase in Texas primarily due to higher long-term debt balances and higher interest rates.

  This increase was partially offset by:
  - A $7 million decrease in Ohio primarily due to the retirement of a higher rate bond, partially offset by the issuance of a lower rate bond in 2021.
- **Income Tax Expense** increased $37 million primarily due to an increase in pretax book income and a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT is partially offset in Gross Margin above.

AEP TRANSMISSION HOLDCO

AEP Transmission Holdco	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
	(in millions)			
Transmission Revenues	$ 430.9	$ 391.6	$ 1,221.1	$ 1,146.8
Other Operation and Maintenance	46.5	40.3	114.4	96.9
Depreciation and Amortization	89.5	78.1	262.7	225.5
Taxes Other Than Income Taxes	70.5	62.7	207.9	183.4
Operating Income	224.4	210.5	636.1	641.0
Interest and Investment Income	0.7	0.3	1.1	0.7
Allowance for Equity Funds Used During Construction	20.3	16.1	51.2	49.3
Non-Service Cost Components of Net Periodic Benefit Cost	1.3	0.5	3.8	1.6
Interest Expense	(44.4)	(37.6)	(124.2)	(108.4)
Income Before Income Tax Expense and Equity Earnings	202.3	189.8	568.0	584.2
Income Tax Expense	52.1	42.0	141.9	131.2
Equity Earnings of Unconsolidated Subsidiary	21.2	20.1	61.7	57.7
Net Income	171.4	167.9	487.8	510.7
Net Income Attributable to Noncontrolling Interests	0.9	1.1	2.4	3.2
Earnings Attributable to AEP Common Shareholders	$ 170.5	$ 166.8	$ 485.4	$ 507.5

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	September 30, 2022	September 30, 2021
	(in millions)	
Plant in Service	$ 12,455.2	$ 11,256.0
Construction Work in Progress	1,752.7	1,609.6
Accumulated Depreciation and Amortization	986.3	758.1
Total Transmission Property, Net	$ 13,221.6	$ 12,107.5

Third Quarter of 2022 Compared to Third Quarter of 2021

Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Third Quarter of 2021	$	166.8
Changes in Transmission Revenues:		
Transmission Revenues		39.3
Total Change in Transmission Revenues		39.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(6.2)
Depreciation and Amortization		(11.4)
Taxes Other Than Income Taxes		(7.8)
Interest and Investment Income		0.4
Allowance for Equity Funds Used During Construction		4.2
Non-Service Cost Components of Net Periodic Pension Cost		0.8
Interest Expense		(6.8)
Total Change in Expenses and Other		(26.8)
Income Tax Expense		(10.1)
Equity Earnings of Unconsolidated Subsidiary		1.1
Net Income Attributable to Noncontrolling Interests		0.2
Third Quarter of 2022	$	170.5

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

- **Transmission Revenues** increased $39 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $6 million primarily due to cancelled capital projects.
- **Depreciation and Amortization** expenses increased $11 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $4 million primarily due to higher CWIP.
- **Interest Expense** increased $7 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $10 million primarily due to an increase in pretax book income and a decrease in parent company loss benefit.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Nine Months Ended September 30, 2021	$	507.5
Changes in Transmission Revenues:		
Transmission Revenues		74.3
Total Change in Transmission Revenues		74.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(17.5)
Depreciation and Amortization		(37.2)
Taxes Other Than Income Taxes		(24.5)
Interest and Investment Income		0.4
Allowance for Equity Funds Used During Construction		1.9
Non-Service Cost Components of Net Periodic Pension Cost		2.2
Interest Expense		(15.8)
Total Change in Expenses and Other		(90.5)
Income Tax Expense		(10.7)
Equity Earnings of Unconsolidated Subsidiary		4.0
Net Income Attributable to Noncontrolling Interests		0.8
Nine Months Ended September 30, 2022	$	485.4

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

- **Transmission Revenues** increased $74 million primarily due to the following:
  - A $117 million increase due to continued investment in transmission assets.

  This increase was partially offset by:
  - A $30 million decrease due to the affiliated annual transmission formula rate true-up. This decrease was offset in Other Operation and Maintenance expense across the other Registrant Subsidiaries.
  - A $13 million decrease due to 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:

- **Other Operation and Maintenance** expenses increased $18 million primarily due to the following:
  - A $15 million increase in employee-related expenses.
  - A $5 million increase due to cancelled capital projects.
- **Depreciation and Amortization** expenses increased $37 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $25 million primarily due to higher property taxes as a result of increased transmission investment.
- **Interest Expense** increased $16 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $11 million primarily due to a decrease in parent company loss benefit, partially offset by a decrease in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiary**increased $4 million primarily due to higher pretax equity earnings for ETT, partially offset by lower pretax equity earnings for Pioneer.

GENERATION & MARKETING

Generation & Marketing	Three Months Ended September 30, 2022		Three Months Ended September 30, 2021		Nine Months Ended September 30, 2022		Nine Months Ended September 30, 2021
			(in millions)				
Revenues	$	735.4	$	621.1	$	2,014.3	$	1,691.9
Fuel, Purchased Electricity and Other		566.1		444.7		1,534.0		1,368.7
Gross Margin		169.3		176.4		480.3		323.2
Other Operation and Maintenance		44.7		38.2		71.2		98.8
Gain on Sale of Mineral Rights		—		—		(116.3)		—
Depreciation and Amortization		23.1		21.1		68.8		59.7
Taxes Other Than Income Taxes		3.1		2.6		9.3		8.1
Operating Income		98.4		114.5		447.3		156.6
Interest and Investment Income		12.5		1.3		21.4		2.4
Non-Service Cost Components of Net Periodic Benefit Cost		5.1		3.8		15.4		11.5
Interest Expense		(16.7)		(4.0)		(30.7)		(11.1)
Income Before Income Tax Expense (Benefit) and Equity Loss		99.3		115.6		453.4		159.4
Income Tax Expense (Benefit)		(5.1)		8.3		(25.3)		(31.0)
Equity Loss of Unconsolidated Subsidiaries		(8.2)		(7.8)		(200.6)		(6.2)
Net Income		96.2		99.5		278.1		184.2
Net Loss Attributable to Noncontrolling Interests		(1.3)		(1.2)		(6.2)		(5.5)
Earnings Attributable to AEP Common Shareholders	$	97.5	$	100.7	$	284.3	$	189.7

Summary of MWhs Generated for Generation & Marketing

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
	(in millions of MWhs)			
Fuel Type:				
Coal	1	1	3	3
Renewables	1	1	3	3
Total MWhs	2	2	6	6

Third Quarter of 2022 Compared to Third Quarter of 2021

Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Third Quarter of 2021	$	100.7
Changes in Gross Margin:		
Merchant Generation		4.5
Renewable Generation		19.2
Retail, Trading and Marketing		(30.8)
Total Change in Gross Margin		(7.1)
Changes in Expenses and Other:		
Other Operation and Maintenance		(6.5)
Depreciation and Amortization		(2.0)
Taxes Other Than Income Taxes		(0.5)
Interest and Investment Income		11.2
Non-Service Cost Components of Net Periodic Benefit Cost		1.3
Interest Expense		(12.7)
Total Change in Expenses and Other		(9.2)
Income Tax Expense		13.4
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(0.4)
Net Income Attributable to Noncontrolling Interests		0.1
Third Quarter of 2022	$	97.5

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

- **Merchant Generation** increased $5 million primarily due to higher market prices.
- **Renewable Generation** increased $19 million primarily due to higher market prices at Texas wind facilities and new solar projects placed in service.
- **Retail, Trading and Marketing** decreased $31 million due to lower gains from mark-to-market economic hedging activity.

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

- **Other Operation and Maintenance** expenses increased $7 million primarily due to the installment sale of Amazon substations in 2021.
- **Interest and Investment Income** increased $11 million primarily due to an increase in advances to affiliates.
- **Interest Expense** increased $13 million due to higher interest rates in 2022.
- **Income Tax Expense** decreased $13 million primarily due to a decrease in pretax book income, an increase in PTCs and a decrease in state income taxes.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Nine Months Ended September 30, 2021	$	189.7
Changes in Gross Margin:		
Merchant Generation		(6.1)
Renewable Generation		35.2
Retail, Trading and Marketing		128.0
Total Change in Gross Margin		157.1
Changes in Expenses and Other:		
Other Operation and Maintenance		27.6
Gain on Sale of Mineral Rights		116.3
Depreciation and Amortization		(9.1)
Taxes Other Than Income Taxes		(1.2)
Interest and Investment Income		19.0
Non-Service Cost Components of Net Periodic Benefit Cost		3.9
Interest Expense		(19.6)
Total Change in Expenses and Other		136.9
Income Tax Benefit		(5.7)
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(194.4)
Net Loss Attributable to Noncontrolling Interests		0.7
Nine Months Ended September 30, 2022	$	284.3

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

- **Merchant Generation** decreased $6 million primarily due to additional Cardinal plant outage days in 2022 and the sale of Racine, partially offset by higher market prices.
- **Renewable Generation** increased $35 million primarily due to higher market prices at Texas wind facilities and new solar projects placed in service.
- **Retail, Trading and Marketing** increased $128 million due to higher mark-to-market economic hedge activity driven by higher commodity prices.

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

- **Other Operation and Maintenance** expenses decreased $28 million primarily due to higher land sales and the sale of renewable development projects.
- **Gain on Sale of Mineral Rights** increased $116 million due to the current year sale of mineral rights.
- **Depreciation and Amortization** expenses increased $9 million due to a higher depreciable base from increased investments in renewable energy assets.
- **Interest and Investment Income** increased $19 million primarily due to an increase in advances to affiliates.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $4 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $20 million due to higher interest rates in 2022.

- **Income Tax Benefit** decreased $6 million primarily due to an increase in pretax book income partially offset by an increase in PTCs and a favorable discrete tax adjustment in 2022.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** decreased $194 million primarily due to the impairment of AEP's investment in Flat Ridge 2 Wind LLC.

CORPORATE AND OTHER

Third Quarter of 2022 Compared to Third Quarter of 2021

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $65 million in 2021 to a loss of $227 million in 2022 primarily due to:

- A $195 million pretax loss related to the anticipated sale of Kentucky operations.
- A $35 million increase in interest expense due to higher interest rates on short-term debt, an increase in advances from affiliates and an increase in long-term debt outstanding.

These items were partially offset by:

- A $28 million increase due to favorable changes in gains and losses from AEP's investment in ChargePoint. As of August 2022, AEP no longer has a direct investment in ChargePoint.
- A $56 million decrease in Income Tax Expense primarily due to the following:
  - A $45 million decrease due to a loss on the anticipated sale of Kentucky operations.
  - A $15 million decrease due to a change in Parent Company Loss Benefit.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $108 million in 2021 to a loss of $406 million in 2022 primarily due to:

- A $263 million pretax loss related to the anticipated sale of Kentucky operations.
- A $54 million increase in interest expense due to higher long-term debt outstanding and higher interest rates on short-term debt.
- A $45 million decrease at EIS, primarily due to lower returns on investments and an increase in reserves.
- A $24 million decrease in equity earnings.
- A $22 million decrease due to unfavorable changes in gains and losses from AEP's investment in ChargePoint. As of August 2022, AEP no longer has a direct investment in ChargePoint.

These items were partially offset by:

- A $103 million decrease in Income Tax Expense primarily due to the following:
  - A $45 million decrease due to a loss on the anticipated sale of Kentucky operations.
  - A $29 million decrease due to a change in pretax book income.
  - A $33 million decrease due to Parent Company Loss Benefit.

AEP SYSTEM INCOME TAXES

Third Quarter of 2022 Compared to Third Quarter of 2021

Income Tax Expense decreased $86 million primarily due to an increase in benefit from PTCs and a decrease in pretax book income.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Income Tax Expense decreased $95 million primarily due to:

- A $73 million decrease due to an increase in PTCs.
- A $25 million decrease due to a decrease in pretax book income.
- A $26 million decrease due to discrete adjustments, primarily driven by the remeasurement of state deferred taxes as a result of newly enacted West Virginia and Oklahoma state legislation in 2021.

These decreases were partially offset by:

- A $33 million increase due to a decrease in amortization of Excess ADIT.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2022		December 31, 2021	
	(dollars in millions)			
Long-term Debt, including amounts due within one year (a)	$ 35,050.1	56.3 %	$ 33,454.5	57.0 %
Short-term Debt	2,702.3	4.3	2,614.0	4.4
Total Debt	37,752.4	60.6	36,068.5	61.4
AEP Common Equity	24,278.2	39.0	22,433.2	38.2
Noncontrolling Interests	234.1	0.4	247.0	0.4
Total Debt and Equity Capitalization	$ 62,264.7	100.0 %	$ 58,748.7	100.0 %

(a) Amount excludes $1.2 billion and $1.1 billion as of September 30, 2022 and December 31, 2021, respectively, of Long-term Debt classified as Liabilities Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

AEP's ratio of debt-to-total capital decreased from 61.4% as of December 31, 2021 to 60.6% as of September 30, 2022 primarily due to the settlement of the forward equity purchase contracts related to the 2019 Equity Units, partially offset by an increase in debt to support distribution, transmission and renewable investment growth. See "Equity Units" section of Note 12 for additional information.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity. As of September 30, 2022, AEP had $5 billion of revolving credit facilities 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. AEP and its utilities finance its operations with commercial paper and other variable rate instruments that are subject to fluctuations in interest rates. To the extent that the Federal Reserve continues to raise short-term interest rates, it could reduce future net income and cash flows and impact financial condition. In February 2021, severe winter weather impacted certain AEP service territories resulting in disruptions to SPP market conditions. See Note 4 - Rate Matters for additional information. In March 2021, AEP entered into a $500 million 364-day Term Loan and borrowed the full amount to help address the cash flow implications resulting from the February 2021 severe winter weather event. In March 2022, AEP extended the maturity date of the original 364-Day Term Loan to August 2022. In August 2022, AEP paid off the $500 million Term Loan. In 2022, increased fuel and purchased power prices continue to lead to an increase in under collection of fuel costs. As a result, in July 2022, APCo and KPCo entered into term loans of $100 million and $75 million, respectively, to help address the cash flow implications of the increased fuel and purchased power costs. See "Deferred Fuel Costs" section of Executive Overview for additional information on how the registrants are addressing the increase in deferred fuel regulatory assets. In September 2022, the ODFA issued ratepayer-backed securitization bonds for the purpose of reimbursing PSO for $687 million of extraordinary fuel costs and purchases of electricity incurred during the February 2021 severe winter weather event. See Note 4 - Rate Matters for additional information.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of September 30, 2022, available liquidity was approximately $3.6 billion as illustrated in the table below:

		Amount	Maturity	
Commercial Paper Backup:		(in millions)		
	Revolving Credit Facility	$ 4,000.0	March 2027	(a)
	Revolving Credit Facility	1,000.0	March 2024	(a)
Cash and Cash Equivalents		522.2		
Total Liquidity Sources		5,522.2		
Less:	AEP Commercial Paper Outstanding	1,952.3		
Net Available Liquidity		$ 3,569.9		

(a) In April 2022, AEP extended the maturity dates of the Revolving Credit Facilities from March 2026 to March 2027 and from March 2023 to March 2024, respectively.

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. The maximum amount of commercial paper outstanding during the first nine months of 2022 was $2.4 billion. The weighted-average interest rate for AEP's commercial paper during 2022 was 1.82%.

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 five uncommitted facilities totaling $400 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2022 was $310 million with maturities ranging from October 2022 to August 2023.

Securitized Accounts Receivables

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and was amended in September 2021 to include a $125 million and a $625 million facility. The $125 million facility was renewed in September 2022 and amended to extend the expiration date to September 2024. The $625 million facility also expires in September 2024. As of September 30, 2022, the affiliated utility subsidiaries are in compliance with all requirements under the agreement.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreement excludes securitization bonds and debt of AEP Credit. As of September 30, 2022, this contractually-defined percentage was 57.7%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP's non-exchange-traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange-traded commodity contracts would not cause an event of default under its credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

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

ATM Program

AEP participates in an ATM offering program that allows AEP to issue, from time to time, up to an aggregate of $1 billion of its common stock, including shares of common stock that may be sold pursuant to an equity forward sales agreement. There were no issuances under the ATM program for the nine months ended September 30, 2022. As of September 30, 2022, approximately $511 million of equity is available for issuance under the ATM offering program. See Note 12 - Financing Activities for additional information.

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 settled after three years in 2022. The proceeds from this issuance were used to support AEP's overall capital expenditure plans including the acquisition of Sempra Renewables LLC.In January 2022, AEP successfully remarketed the notes on behalf of holders of the corporate units and did not directly receive any proceeds therefrom. Instead, the holders of the corporate units used the debt remarketing proceeds to settle the forward equity purchase contract with AEP. The interest rate on the notes was reset to 2.031% with the maturity remaining in 2024. In March 2022, AEP issued 8,970,920 shares of AEP common stock and received proceeds totaling $805 million under the settlement of the forward equity purchase contract. AEP common stock held in treasury was used to settle the forward equity purchase contract.

See Note 12 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.83 per share in October 2022.Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends. Management does not believe these restrictions will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 12 for additional information.

Credit Ratings

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

CASH FLOW

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

	Nine Months Ended September 30,	
	2022	2021
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 451.4	$ 438.3
Net Cash Flows from Operating Activities	4,733.2	2,973.0
Net Cash Flows Used for Investing Activities	(5,822.5)	(4,906.2)
Net Cash Flows from Financing Activities	1,215.2	2,921.6
Net Increase in Cash and Cash Equivalents	125.9	988.4
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 577.3	$ 1,426.7

Operating Activities

	Nine Months Ended September 30,	
	2022	2021
	(in millions)	
Net Income	$ 1,922.2	$ 1,949.5
Non-Cash Adjustments to Net Income (a)	2,661.1	2,191.1
Mark-to-Market of Risk Management Contracts	162.3	101.0
Property Taxes	459.9	415.1
Deferred Fuel Over/Under-Recovery, Net	(148.7)	(1,356.8)
Change in Other Noncurrent Assets	(6.0)	(108.0)
Change in Other Noncurrent Liabilities	324.0	162.7
Change in Certain Components of Working Capital	(641.6)	(381.6)
Net Cash Flows from Operating Activities	$ 4,733.2	$ 2,973.0

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Deferred Income Taxes, Loss on the Expected Sale of the Kentucky Operations, Asset Impairments and Other Related Charges, Impairment of Equity Method Investment, AFUDC, Gain on Sale of Mineral Rights and Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset.

Net Cash Flows from Operating Activities increased by $1.8 billion primarily due to the following:

- A $1.2 billion increase in cash primarily due to the timing of fuel and purchase power revenues and expenses. PSO and SWEPCo were impacted by the February 2021 severe winter weather event in SPP which led to significantly higher fuel and purchased power expenses which were deferred as regulatory assets in 2021. In September 2022, the ODFA issued ratepayer-backed securitization bonds and provided PSO proceeds of $687 million as reimbursement of the extraordinary fuel costs and purchased electricity incurred during the severe winter weather event. See Note 4 - Rate Matters for additional information.In 2022, increased fuel and purchased power prices in excess of amounts included in fuel-related revenues has resulted in an increase in the under collection of fuel costs in most jurisdictions, offsetting the proceeds received by PSO in September 2022. See the "Deferred Fuel Costs" section of Executive Overview for additional information.

- A $443 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.
- A $161 million increase in cash from the Change in Other Noncurrent Liabilities. The increase is primarily due to changes in regulatory liabilities driven by timing differences between collections from and refunds to customers under rate rider mechanisms.
- A $102 million increase in cash from the Change in Other Noncurrent Assets primarily due to incremental other operation and maintenance storm restoration expenses incurred in 2021 by APCo, SWEPCo and KPCo as a result of the February 2021 severe winter weather event KPCo intends to seek recovery of these incremental storm costs in its next base rate case while APCo is expected to seek recovery in either upcoming rider or base case filings. In October 2021, SWEPCo requested recovery of these storm costs, in addition to storm costs from Hurricanes Delta and Laura, in a filing with the LPSC. The increase due to the February 2021 severe winter weather event was partially offset by the deferral of incremental other operation and maintenance storm restoration expenses incurred in June 2022 by APCo, KPCo, OPCo and WPCo. Recovery of the June 2022 storm costs will be requested in future filings. See Note 4 - Rate Matters for additional information.

These increases in cash were partially offset by:

- A $260 million decrease in cash from the Change in Certain Components of Working Capital. The decrease is primarily due to fuel, material and supplies driven by prior year decreases in coal and lignite inventory on hand, an increase in estimated federal income taxes paid and the timing of accounts receivables. These decreases were partially offset by the timing of accounts payable and a return of margin deposits from PJM originally paid in 2021.

Investing Activities

	Nine Months Ended September 30,	
	2022	2021
	(in millions)	
Construction Expenditures	$ (4,748.5)	$ (4,087.0)
Acquisitions of Nuclear Fuel	(91.9)	(63.2)
Acquisition of the Dry Lake Solar Project	—	(114.4)
Acquisition of the North Central Wind Energy Facilities	(1,207.3)	(652.8)
Proceeds from Sale of Assets	215.7	17.4
Other	9.5	(6.2)
Net Cash Flows Used for Investing Activities	$ (5,822.5)	$ (4,906.2)

Net Cash Flows Used for Investing Activities increased by $916 million primarily due to the following:

- A $662 million increase in Construction Expenditures, primarily due to increases in Vertically Integrated Utilities of $437 million and Transmission and Distribution Utilities of $271 million.
- A $440 million increase due to the 2022 acquisition of Traverse, partially offset by the 2021 acquisitions of the Dry Lake Solar Project and Sundance. See Note 6 - Acquisitions, Assets and Liabilities Held for Sale, Dispositions and Impairments for additional information.

These increases in cash used were partially offset by:

- A $198 million increase in Proceeds from Sale of Assets, primarily due to the sale of certain mineral rights. See Note 6 - Acquisitions, Assets and Liabilities Held for Sale, Dispositions and Impairments for additional information.

Financing Activities

	Nine Months Ended September 30, 2022	2021
	(in millions)	
Issuance of Common Stock	$ 827.2	$ 548.0
Issuance/Retirement of Debt, Net	1,837.6	3,537.2
Dividends Paid on Common Stock	(1,212.5)	(1,122.7)
Other	(237.1)	(40.9)
Net Cash Flows from Financing Activities	$ 1,215.2	$ 2,921.6

Net Cash Flows from Financing Activities decreased by $1.7 billion primarily due to the following:

- A $1.6 billion decrease in issuances of long-term debt. See Note 12 - Financing Activities for additional information.
- A $129 million increase in retirements of long-term debt. See Note 12 - Financing Activities for additional information.

These decreases in cash were partially offset by:

- A $279 million increase in issuances of common stock primarily due to the settlement of the 2019 equity units. See "Equity Units" section of Note 12 for additional information.
- A $64 million increase due to changes in short-term debt. See Note 12 - Financing Activities for additional information.

See the "Long-term Debt Subsequent Events" section of Note 12 for Long-term debt and other securities issued, retired and principal payments made after September 30, 2022 through October 27, 2022, the date that the third quarter 10-Q was filed.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $7.6 billion of capital expenditures in 2022. For the four year period, 2023 through 2026, management forecasts capital expenditures of $32.9 billion. The expenditures are generally for transmission, generation, distribution, regulated 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, supply chain issues, weather, legal reviews, inflation and the ability to access capital. Management expects to fund these capital expenditures through cash flows from operations, proceeds from the sale of Kentucky operations, proceeds from the sale of competitive contracted renewables and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. For complete information of forecasted capital expenditures, see the "Budgeted Capital Expenditures" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2021 Annual Report.

SIGNIFICANT CASH REQUIREMENTS

A summary of significant cash requirements is included in the 2021 Annual Report and has not changed significantly from year-end other than the debt issuances and retirements discussed in the "Cash Flow" section above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

See the "Critical Accounting Policies and Estimates" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2021 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and the impact of new accounting standards.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards. There are no new standards expected to have a material impact to the Registrants' financial statements.

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 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 President & Chief Financial Officer, Chief Operating Officer, Executive Vice President of Generation, Senior Vice President of Grid Solutions, Senior Vice President of Treasury and Risk and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's President & Chief Financial Officer, Senior Vice President of Treasury and Risk and Chief Risk Officer in addition to Chief Commercial Officer and Senior Vice President of Financial and Commercial Operations. 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 continue to be monitored, and while markets have shown improvement, credit risks remain as counterparties encounter business and supply chain disruptions.

Due to multiple defaults of market participants, ERCOT had a large outstanding unpaid balance associated with the February 2021 winter storm.A certain portion of this balance has been securitized and disbursed to impacted market participants. A recovery plan has been reached by ERCOT for the remaining portion of the outstanding balance. In both cases, financial costs are allocated to certain market participants and in the role AEPEP is exposed, but not materially. If the market rules were to change on how socialized losses are allocated this could affect AEPEP's exposure. Regardless of the approach of how socialized losses are allocated there are potential downstream impacts that could push counterparties into financial distress and or bankruptcy, affecting AEPEP, AEP Texas and ETT.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2021:

MTM Risk Management Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2022

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2021	$ 59.8	$ (91.4)	$ 275.9	$ 244.3
(Gain)/Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(65.5)	3.7	(50.0)	(111.8)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	0.9	0.9
Changes in Fair Value Due to Market Fluctuations During the Period (b)	1.9	—	265.4	267.3
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	224.5	44.6	—	269.1
MTM Risk Management Contract Net Assets Held for Sale Related to KPCo (d)	(8.4)	—	—	(8.4)
Total MTM Risk Management Contract Net Assets (Liabilities) as of September 30, 2022	$ 212.3	$ (43.1)	$ 492.2	661.4
Commodity Cash Flow Hedge Contracts				572.7
Interest Rate Cash Flow Hedge Contracts				8.8
Fair Value Hedge Contracts				(135.4)
Collateral Deposits				(847.0)
Total MTM Derivative Contract Net Assets as of September 30, 2022				$ 260.5

(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 on the balance sheet.
(d) MTM risk management contract net assets relating to KPCo are classified as Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

See Note 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

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

AEP has risk management contracts (includes non-derivative contracts) with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of September 30, 2022, credit exposure net of collateral to sub investment grade counterparties was approximately 0.8%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss).

As of September 30, 2022, 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	$ 830.1	$ 399.5	$ 430.6	3	$ 186.4
Split Rating	0.8	—	0.8	1	0.8
Noninvestment Grade	2.5	2.4	0.1	1	0.1
No External Ratings:					
Internal Investment Grade	32.1	—	32.1	3	24.7
Internal Noninvestment Grade	16.7	13.2	3.5	4	3.4
Total as of September 30, 2022	$ 882.2	$ 415.1	$ 467.1		

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

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of September 30, 2022, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

Management calculates the VaR for both a trading and non-trading portfolio. The trading portfolio consists primarily of contracts related to energy trading and marketing activities. The non-trading portfolio consists primarily of economic hedges of generation and retail supply activities.

The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio

Nine Months Ended September 30, 2022				Twelve Months Ended December 31, 2021			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.4	$ 4.5	$ 0.8	$ 0.1	$ 0.4	$ 3.6	$ 0.4	$ 0.1

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2022				Twelve Months Ended December 31, 2021			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 16.6	$ 76.9	$ 26.0	$ 6.7	$ 8.3	$ 14.9	$ 3.7	$ 0.7

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. Recently, interest rates have remained at relatively low levels on a historical basis and the Federal Reserve maintained the federal funds target range at 0.0% to 0.25% for much of 2021. However, in March 2022, the Federal Reserve approved a 0.25% rate increase and in each of June, July and September of 2022 approved further 0.75% rate increases. The Federal Reserve has indicated that, in light of increasing signs of inflation, it foresees further increases in interest rates throughout the year and into 2023 and 2024. AEP has outstanding short and long-term debt which is subject to variable rates. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the nine months ended September 30, 2022 and 2021, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $47 million and $32 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
REVENUES				
Vertically Integrated Utilities	$ 3,174.6	$ 2,716.8	$ 8,416.4	$ 7,445.9
Transmission and Distribution Utilities	1,525.5	1,195.0	4,064.5	3,366.9
Generation & Marketing	733.1	617.4	1,997.0	1,641.6
Other Revenues	92.9	93.8	280.5	276.2
TOTAL REVENUES	5,526.1	4,623.0	14,758.4	12,730.6
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	2,111.9	1,441.4	5,177.0	4,126.1
Other Operation	797.0	735.3	2,079.0	1,894.6
Maintenance	298.1	277.8	909.6	817.0
Loss on the Expected Sale of the Kentucky Operations	194.5	—	263.3	—
Asset Impairments and Other Related Charges	24.9	—	24.9	—
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—	(37.0)	—
Gain on Sale of Mineral Rights	—	—	(116.3)	—
Depreciation and Amortization	821.8	700.3	2,416.8	2,103.9
Taxes Other Than Income Taxes	384.8	360.8	1,118.5	1,061.4
TOTAL EXPENSES	4,596.0	3,515.6	11,835.8	10,003.0
OPERATING INCOME	930.1	1,107.4	2,922.6	2,727.6
Other Income (Expense):				
Other Income (Expense)	4.8	(20.6)	(5.6)	34.2
Allowance for Equity Funds Used During Construction	35.6	37.0	95.2	103.9
Non-Service Cost Components of Net Periodic Benefit Cost	47.2	29.6	141.5	88.9
Interest Expense	(360.7)	(303.7)	(1,001.7)	(895.5)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS (LOSS)	657.0	849.7	2,152.0	2,059.1
Income Tax Expense (Benefit)	(16.1)	69.8	90.7	185.5
Equity Earnings (Loss) of Unconsolidated Subsidiaries	10.2	17.0	(139.1)	75.9
NET INCOME	683.3	796.9	1,922.2	1,949.5
Net Income (Loss) Attributable to Noncontrolling Interests	(0.4)	0.9	(0.7)	0.3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 683.7	$ 796.0	$ 1,922.9	$ 1,949.2
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	513,730,196	501,233,680	511,162,723	499,418,278
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.33	$ 1.59	$ 3.76	$ 3.90
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	515,315,994	502,606,836	512,714,006	500,600,237
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.33	$ 1.58	$ 3.75	$ 3.89

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
et Income	$ 683.3	$ 796.9	$ 1,922.2	$ 1,949.5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(19.5) and $47.8 for the Three Months Ended September 30, 2022 and 2021, Respectively, and $81.6 and $97.3 for the Nine Months Ended September 30, 2022 and 2021, Respectively	(73.3)	179.7	307.1	365.9
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.8) and $(0.5) for the Three Months Ended September 30, 2022 and 2021 and $(4.5) and $(1.6) for the Nine Months Ended September 30, 2022 and 2021, Respectively	(3.2)	(2.0)	(17.0)	(6.1)
OTAL OTHER COMPREHENSIVE INCOME (LOSS)	(76.5)	177.7	290.1	359.8
OTAL COMPREHENSIVE INCOME	606.8	974.6	2,212.3	2,309.3
Total Comprehensive Income (Loss) Attributable To Noncontrolling Interests	(0.4)	0.9	(0.7)	0.3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 607.2	$ 973.7	$ 2,213.0	$ 2,309.0

e Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2020	516.8	$ 3,359.3	$ 6,588.9	$ 10,687.8	$ (85.1)	$ 223.6	$ 20,774.5
Issuance of Common Stock	2.7	17.1	167.5				184.6
Common Stock Dividends				(369.5) (a)		(2.5)	(372.0)
Other Changes in Equity			(21.9)	(0.6)		3.4	(19.1)
Acquisition of Dry Lake Solar Project						18.9	18.9
Net Income				575.0		3.8	578.8
Other Comprehensive Income					54.3		54.3
TOTAL EQUITY – MARCH 31, 2021	519.5	3,376.4	6,734.5	10,892.7	(30.8)	247.2	21,220.0
Issuance of Common Stock	0.9	6.3	66.0				72.3
Common Stock Dividends				(371.8) (a)		(2.7)	(374.5)
Other Changes in Equity			(0.2)	(0.4)		11.1	10.5
Net Income (Loss)				578.2		(4.4)	573.8
Other Comprehensive Income					127.8		127.8
TOTAL EQUITY – JUNE 30, 2021	520.4	3,382.7	6,800.3	11,098.7	97.0	251.2	21,629.9
Issuance of Common Stock	3.4	21.8	269.3				291.1
Common Stock Dividends				(371.7) (a)		(4.5)	(376.2)
Other Changes in Equity			6.3			1.5	7.8
Net Income				796.0		0.9	796.9
Other Comprehensive Income					177.7		177.7
TOTAL EQUITY – SEPTEMBER 30, 2021	523.8	$ 3,404.5	$ 7,075.9	$ 11,523.0	$ 274.7	$ 249.1	$ 22,527.2
TOTAL EQUITY – DECEMBER 31, 2021	524.4	$ 3,408.7	$ 7,172.6	$ 11,667.1	$ 184.8	$ 247.0	$ 22,680.2
Issuance of Common Stock	0.4	2.4	807.1				809.5
Common Stock Dividends				(395.2) (b)		(3.6)	(398.8)
Other Changes in Equity			(15.2)	(1.5)			(16.7)
Net Income				714.7		3.4	718.1
Other Comprehensive Income					245.8		245.8
TOTAL EQUITY – MARCH 31, 2022	524.8	3,411.1	7,964.5	11,985.1	430.6	246.8	24,038.1
Issuance of Common Stock	0.1	0.9	2.3				3.2
Common Stock Dividends				(402.6) (b)		(2.1)	(404.7)
Other Changes in Equity			17.2	1.6			18.8
Net Income (Loss)				524.5		(3.7)	520.8
Other Comprehensive Income					120.8		120.8
TOTAL EQUITY – JUNE 30, 2022	524.9	3,412.0	7,984.0	12,108.6	551.4	241.0	24,297.0
Issuance of Common Stock	0.1	0.5	14.0				14.5
Common Stock Dividends				(402.5) (b)		(6.5)	(409.0)
Other Changes in Equity			3.0				3.0
Net Income (Loss)				683.7		(0.4)	683.3
Other Comprehensive Loss					(76.5)		(76.5)
TOTAL EQUITY – SEPTEMBER 30, 2022	525.0	$ 3,412.5	$ 8,001.0	$ 12,389.8	$ 474.9	$ 234.1	$ 24,512.3

(a) Cash dividends declared per AEP common share were $0.74.
(b) Cash dividends declared per AEP common share were $0.78.

ondensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 522.2	$ 403.4
Restricted Cash (September 30, 2022 and December 31, 2021 Amounts Include $55.1 and $48, Respectively, Related to Transition Funding, Restoration Funding and Appalachian Consumer Rate Relief Funding)	55.1	48.0
Other Temporary Investments (September 30, 2022 and December 31, 2021 Amounts Include $188.4 and $214.8, Respectively, Related to EIS and Transource Energy)	202.2	220.4
Accounts Receivable:		
Customers	885.6	720.9
Accrued Unbilled Revenues	272.2	204.4
Pledged Accounts Receivable – AEP Credit	1,211.9	1,038.0
Miscellaneous	84.8	33.9
Allowance for Uncollectible Accounts	(53.2)	(55.6)
Total Accounts Receivable	2,401.3	1,941.6
Fuel	332.1	307.9
Materials and Supplies	801.9	681.3
Risk Management Assets	570.2	194.4
Accrued Tax Benefits	150.8	121.5
Regulatory Asset for Under-Recovered Fuel Costs	1,137.1	647.8
Assets Held for Sale	2,830.6	2,919.7
Prepayments and Other Current Assets	316.5	323.2
TOTAL CURRENT ASSETS	9,320.0	7,809.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,590.7	23,088.1
Transmission	31,271.5	29,911.1
Distribution	25,566.1	24,440.0
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	6,080.8	5,682.9
Construction Work in Progress	4,596.0	3,684.3
Total Property, Plant and Equipment	92,105.1	86,806.4
Accumulated Depreciation and Amortization	22,292.0	20,805.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	69,813.1	66,001.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,877.5	4,142.3
Securitized Assets	474.3	552.8
Spent Nuclear Fuel and Decommissioning Trusts	3,130.5	3,867.0
Goodwill	52.5	52.5
Long-term Risk Management Assets	265.8	267.0
Operating Lease Assets	620.0	578.3
Deferred Charges and Other Noncurrent Assets	3,695.7	4,398.3
TOTAL OTHER NONCURRENT ASSETS	12,116.3	13,858.2
TOTAL ASSETS	$ 91,249.4	$ 87,668.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2022 and December 31, 2021
(in millions, except per-share and share amounts)
(Unaudited)

			September 30, 2022	December 31, 2021
CURRENT LIABILITIES				
Accounts Payable			$ 2,240.2	$ 2,054.6
Short-term Debt:				
Securitized Debt for Receivables – AEP Credit			750.0	750.0
Other Short-term Debt			1,952.3	1,864.0
Total Short-term Debt			2,702.3	2,614.0
Long-term Debt Due Within One Year (September 30, 2022 and December 31, 2021 Amounts Include $196.4 and $190.5, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			1,403.5	2,153.8
Risk Management Liabilities			187.3	75.4
Customer Deposits			375.5	321.6
Accrued Taxes			1,116.9	1,586.4
Accrued Interest			375.4	273.2
Obligations Under Operating Leases			91.7	97.6
Liabilities Held for Sale			1,992.0	1,880.9
Other Current Liabilities			1,351.6	1,369.2
TOTAL CURRENT LIABILITIES			11,836.4	12,426.7
NONCURRENT LIABILITIES				
Long-term Debt (September 30, 2022 and December 31, 2021 Amounts Include $764 and $840.5, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			33,646.6	31,300.7
Long-term Risk Management Liabilities			388.2	230.3
Deferred Income Taxes			8,544.8	8,202.5
Regulatory Liabilities and Deferred Investment Tax Credits			7,934.1	8,686.3
Asset Retirement Obligations			2,855.1	2,676.2
Employee Benefits and Pension Obligations			279.9	328.4
Obligations Under Operating Leases			540.0	492.8
Deferred Credits and Other Noncurrent Liabilities			638.7	601.3
TOTAL NONCURRENT LIABILITIES			54,827.4	52,518.5
TOTAL LIABILITIES			66,663.8	64,945.2
Rate Matters (Note 4)				
Commitments and Contingencies (Note 5)				
MEZZANINE EQUITY				
Contingently Redeemable Performance Share Awards			73.3	43.3
TOTAL MEZZANINE EQUITY			73.3	43.3
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2022	**2021**		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	525,005,433	524,416,175		
(11,233,240 Shares and 20,204,160 Shares were Held in Treasury as of September 30, 2022 and December 31, 2021, Respectively)			3,412.5	3,408.7
Paid-in Capital			8,001.0	7,172.6
Retained Earnings			12,389.8	11,667.1
Accumulated Other Comprehensive Income (Loss)			474.9	184.8
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			24,278.2	22,433.2
Noncontrolling Interests			234.1	247.0
TOTAL EQUITY			24,512.3	22,680.2
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$ 91,249.4	$ 87,668.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
OPERATING ACTIVITIES		
Net Income	$ 1,922.2	$ 1,949.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	2,416.8	2,103.9
Deferred Income Taxes	16.6	191.1
Loss on the Expected Sale of the Kentucky Operations	263.3	—
Asset Impairments and Other Related Charges	24.9	—
Impairment of Equity Method Investment	188.0	—
Allowance for Equity Funds Used During Construction	(95.2)	(103.9)
Mark-to-Market of Risk Management Contracts	162.3	101.0
Property Taxes	459.9	415.1
Deferred Fuel Over/Under-Recovery, Net	(148.7)	(1,356.8)
Gain on Sale of Mineral Rights	(116.3)	—
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—
Change in Other Noncurrent Assets	(6.0)	(108.0)
Change in Other Noncurrent Liabilities	324.0	162.7
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(495.7)	(199.2)
Fuel, Materials and Supplies	(134.6)	347.4
Accounts Payable	369.4	107.6
Accrued Taxes, Net	(512.8)	(471.1)
Other Current Assets	41.2	(33.3)
Other Current Liabilities	90.9	(133.0)
Net Cash Flows from Operating Activities	4,733.2	2,973.0
INVESTING ACTIVITIES		
Construction Expenditures	(4,748.5)	(4,087.0)
Purchases of Investment Securities	(1,868.2)	(1,612.3)
Sales of Investment Securities	1,833.4	1,571.7
Acquisitions of Nuclear Fuel	(91.9)	(63.2)
Acquisition of the Dry Lake Solar Project	—	(114.4)
Acquisition of the North Central Wind Energy Facilities	(1,207.3)	(652.8)
Proceeds from Sales of Assets	215.7	17.4
Other Investing Activities	44.3	34.4
Net Cash Flows Used for Investing Activities	(5,822.5)	(4,906.2)
FINANCING ACTIVITIES		
Issuance of Common Stock	827.2	548.0
Issuance of Long-term Debt	3,428.4	5,062.3
Issuance of Short-term Debt with Original Maturities greater than 90 Days	271.0	1,178.5
Change in Short-term Debt with Original Maturities less than 90 Days, Net	803.4	(632.5)
Retirement of Long-term Debt	(1,679.1)	(1,549.8)
Redemption of Short-term Debt with Original Maturities Greater than 90 Days	(986.1)	(521.3)
Principal Payments for Finance Lease Obligations	(120.3)	(45.3)
Dividends Paid on Common Stock	(1,212.5)	(1,122.7)
Other Financing Activities	(116.8)	4.4
Net Cash Flows from Financing Activities	1,215.2	2,921.6
Net Increase in Cash and Cash Equivalents	125.9	988.4
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	451.4	438.3
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 577.3	$ 1,426.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TEXAS INC.
AND SUBSIDIARIES

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions of KWhs)			
Retail:				
Residential	4,079	3,997	10,453	9,821
Commercial	3,243	3,014	8,482	7,907
Industrial	2,993	2,414	8,443	6,898
Miscellaneous	185	182	499	478
Total Retail	10,500	9,607	27,877	25,104

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in degree days)			
Actual – Heating (a)	—	—	278	319
Normal – Heating (b)	—	—	193	188
Actual – Cooling (c)	1,478	1,308	2,701	2,278
Normal – Cooling (b)	1,382	1,379	2,433	2,436

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

Third Quarter of 2022 Compared to Third Quarter of 2021

AEP Texas Inc. and Subsidiaries
Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Net Income
(in millions)

Third Quarter of 2021	$	99.5
Changes in Revenues:		
Retail Revenues		44.0
Transmission Revenues		9.3
Other Revenues		23.0
Total Change in Revenues		76.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(29.2)
Depreciation and Amortization		(30.1)
Taxes Other Than Income Taxes		(3.9)
Interest Income		1.1
Allowance for Equity Funds Used During Construction		(4.0)
Non-Service Cost Components of Net Periodic Benefit Cost		1.4
Interest Expense		(11.2)
Total Change in Expenses and Other		(75.9)
Income Tax Expense		(6.3)
Third Quarter of 2022	$	93.6

The major components of the increase in revenues were as follows:

- **Retail Revenues** increased $44 million primarily due to the following:
  - A $21 million increase due to interim rate increases driven by increased transmission investment.
  - A $10 million increase due to interim rate increases driven by increased distribution investment.
  - A $7 million increase in weather-related usage primarily due to a 13% increase in cooling degree days.
  - A $6 million increase in revenue from rate riders. This increase was partially offset in other expense items below.
- **Transmission Revenues** increased $9 million primarily due to the following:
  - An $11 million increase due to interim rate increases driven by increased transmission investment.

This increase was partially offset by:

  - A $2 million decrease due to prior year refunds to customers associated with the most recent base rate case. This decrease was offset in Other Revenues below.
- **Other Revenues** increased $23 million primarily due to the following:
  - A $19 million increase primarily due to securitization revenues due to AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset below in Depreciation and Amortization expenses and Interest Expense.

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

- **Other Operation and Maintenance** expenses increased $29 million primarily due to the following:
  - A $21 million increase in ERCOT transmission expenses.This increase was partially offset in Retail Revenues and Transmission Revenues above.
  - A $6 million increase in distribution-related expenses.
- **Depreciation and Amortization** expenses increased $30 million primarily due to the following:
  - A $19 million increase in securitization amortizations primarily due to prior year AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset above in Other Revenues above.
  - A $6 million increase due to a higher depreciable base of transmission and distribution assets.
  - A $4 million increase in recoverable advanced metering system depreciable expenses.
- **Taxes Other Than Income Taxes** increased $4 million primarily due to property taxes as a result of increased distribution and transmission investment.
- **Allowance for Equity Funds Used During Construction** decreased $4 million due to a prior year rate adjustment.
- **Interest Expense** increased $11 million primarily due to higher long-term debt balances and higher interest rates.
- **Income Tax Expense** increased $6 million primarily due to a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT was offset in Retail Revenues above.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

AEP Texas Inc. and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Net Income
(in millions)

Nine Months Ended September 30, 2021	$	225.4
Changes in Revenues:		
Retail Revenues		151.2
Transmission Revenues		53.2
Other Revenues		4.7
Total Change in Revenues		209.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(74.8)
Depreciation and Amortization		(55.6)
Taxes Other Than Income Taxes		(8.4)
Interest Income		2.1
Allowance for Equity Funds Used During Construction		(3.5)
Non-Service Cost Components of Net Periodic Benefit Cost		4.2
Interest Expense		(20.7)
Total Change in Expenses and Other		(156.7)
Income Tax Expense		(24.6)
Nine Months Ended September 30, 2022	$	253.2

The major components of the increase in revenues were as follows:

- **Retail Revenues** increased $151 million primarily due to the following:
  - A $41 million increase due to interim rate increases driven by increased transmission investment.
  - A $31 million increase due to prior year refunds of Excess ADIT to customers. This increase was offset in Income Tax Expense below.
  - A $29 million increase due to interim rate increases driven by increased distribution investment.
  - A $20 million increase in revenue from rate riders. This increase was partially offset in other expense items below.
  - A $16 million increase in weather-normalized revenues in all retail classes.
  - A $15 million increase in weather-related usage primarily due to a 19% increase in cooling degree days partially offset by a 13% decrease in heating degree days.
- **Transmission Revenues** increased $53 million primarily due to the following:
  - A $46 million increase due to interim rate increases driven by increased transmission investment.
  - A $7 million increase due to prior year refunds to customers associated with the most recent base rate case. This increase was offset in Other Revenues below.
- **Other Revenues** increased $5 million primarily due to:
  - A $20 million increase primarily due to securitization revenues driven by the AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset below in Depreciation and Amortization expenses and Interest Expense.
  - A $2 million increase in pole attachment revenues.

These increases were partially offset by:

- A $12 million decrease due to prior year refunds to customers associated with the most recent base rate case. This decrease was partially offset in Retail Revenues and Transmission Revenues above.
- A $5 million decrease in energy efficiency revenues.

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

- **Other Operation and Maintenance** expenses increased $75 million primarily due to the following:
  - A $46 million increase in ERCOT transmission expenses.This increase was partially offset in Retail Revenues and Transmission Revenues above.
  - A $13 million increase in distribution-related expenses.
  - A $10 million increase in employee-related expenses.
  - A $5 million increase in vegetation management expenses.
- **Depreciation and Amortization** expenses increased $56 million primarily due to the following:
  - A $24 million increase due to a higher depreciable base and amortizations of transmission and distribution assets.
  - A $19 million increase in securitization amortizations primarily due to prior year AEP Texas Central Transition Funding II LLC bonds that matured in July 2020 and final refunds that were completed in 2021. This increase was offset above in Other Revenue.
  - An $11 million increase in recoverable advanced metering system depreciable expenses.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to property taxes as a result of increased distribution and transmission investment.
- **Allowance for Equity Funds Used During Construction** decreased $4 million due to a prior year rate adjustment.
- **Non-Service Cost Components of Net Periodic Benefit Cost**decreased $4 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $21 million primarily due to higher long-term debt balances and higher interest rates.
- **Income Tax Expense** increased $25 million primarily due to an increase in pretax book income and a decrease in amortization of Excess ADIT. The decrease in amortization of Excess ADIT was offset in Retail Revenues above.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
REVENUES				
Electric Transmission and Distribution	$ 507.7	$ 430.8	$ 1,399.3	$ 1,189.1
Sales to AEP Affiliates	0.9	0.9	2.6	2.9
Other Revenues	0.3	0.9	2.5	3.3
TOTAL REVENUES	508.9	432.6	1,404.4	1,195.3
EXPENSES				
Other Operation	163.8	135.3	431.6	367.1
Maintenance	22.7	22.0	70.1	59.8
Depreciation and Amortization	117.7	87.6	342.7	287.1
Taxes Other Than Income Taxes	45.5	41.6	125.8	117.4
TOTAL EXPENSES	349.7	286.5	970.2	831.4
OPERATING INCOME	159.2	146.1	434.2	363.9
Other Income (Expense):				
Interest Income	1.3	0.2	2.7	0.6
Allowance for Equity Funds Used During Construction	5.2	9.2	13.2	16.7
Non-Service Cost Components of Net Periodic Benefit Cost	4.2	2.8	12.5	8.3
Interest Expense	(55.4)	(44.2)	(153.2)	(132.5)
INCOME BEFORE INCOME TAX EXPENSE	114.5	114.1	309.4	257.0
Income Tax Expense	20.9	14.6	56.2	31.6
NET INCOME	$ 93.6	$ 99.5	$ 253.2	$ 225.4

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Net Income	$ 93.6	$ 99.5	$ 253.2	$ 225.4
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2022 and 2021, Respectively, and $0.2 and $0.2 for the Nine Months Ended September 30, 2022 and 2021, Respectively	0.3	0.3	0.8	0.8
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2022 and 2021, Respectively, and $0 and $0 for the Nine Months Ended September 30, 2022 and 2021, Respectively	—	—	—	0.1
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.3	0.8	0.9
TOTAL COMPREHENSIVE INCOME	$ 93.9	$ 99.8	$ 254.0	$ 226.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 1,457.9	$ 1,757.0	$ (8.9)	$ 3,206.0
Net Income		46.1		46.1
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2021	1,457.9	1,803.1	(8.6)	3,252.4
Net Income		79.8		79.8
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2021	1,457.9	1,882.9	(8.3)	3,332.5
Net Income		99.5		99.5
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2021	$ 1,457.9	$ 1,982.4	$ (8.0)	$ 3,432.3
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2021	$ 1,553.9	$ 2,046.8	$ (6.5)	$ 3,594.2
Net Income		69.6		69.6
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2022	1,553.9	2,116.4	(6.2)	3,664.1
Capital Contribution from Parent	1.3			1.3
Net Income		90.0		90.0
Other Comprehensive Income			0.2	0.2
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2022	1,555.2	2,206.4	(6.0)	3,755.6
Capital Contribution from Parent	0.5			0.5
Net Income		93.6		93.6
Other Comprehensive Income			0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2022	$ 1,555.7	$ 2,300.0	$ (5.7)	$ 3,850.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 0.1	$ 0.1
Restricted Cash (September 30, 2022 and December 31, 2021 Amounts Include $47.7 and $30.4, Respectively, Related to Transition Funding and Restoration Funding)	47.7	30.4
Advances to Affiliates	136.3	6.9
Accounts Receivable:		
Customers	166.0	123.4
Affiliated Companies	5.9	7.9
Accrued Unbilled Revenues	94.7	77.9
Miscellaneous	0.2	—
Allowance for Uncollectible Accounts	(4.1)	(4.0)
Total Accounts Receivable	262.7	205.2
Materials and Supplies	113.8	73.9
Risk Management Assets	0.2	—
Accrued Tax Benefits	21.7	24.8
Prepayments and Other Current Assets	6.5	5.9
TOTAL CURRENT ASSETS	589.0	347.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	6,154.4	5,849.9
Distribution	5,192.3	4,917.2
Other Property, Plant and Equipment	1,013.6	961.1
Construction Work in Progress	697.7	551.3
Total Property, Plant and Equipment	13,058.0	12,279.5
Accumulated Depreciation and Amortization	1,746.3	1,644.1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	11,311.7	10,635.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	243.9	275.2
Securitized Assets (September 30, 2022 and December 31, 2021 Amounts Include $308.3 and $367.6, Respectively, Related to Transition Funding and Restoration Funding)	308.3	367.6
Long-term Risk Management Assets	0.1	—
Deferred Charges and Other Noncurrent Assets	237.0	211.3
TOTAL OTHER NONCURRENT ASSETS	789.3	854.1
TOTAL ASSETS	$ 12,690.0	$ 11,836.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 26.9
Accounts Payable:		
General	249.2	306.3
Affiliated Companies	32.6	32.5
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2022 and December 31, 2021 Amounts Include $92.5 and $91, Respectively, Related to Transition Funding and Restoration Funding)	277.5	716.0
Accrued Taxes	129.6	93.3
Accrued Interest (September 30, 2022 and December 31, 2021 Amounts Include $2.5 and $2.3, Respectively, Related to Transition Funding and Restoration Funding)	72.3	44.7
Obligations Under Operating Leases	14.0	14.0
Other Current Liabilities	110.5	78.0
TOTAL CURRENT LIABILITIES	885.7	1,311.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2022 and December 31, 2021 Amounts Include $259.2 and $313.7, Respectively, Related to Transition Funding and Restoration Funding)	5,416.4	4,464.8
Long-term Risk Management Liabilities	0.1	—
Deferred Income Taxes	1,132.2	1,088.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,258.3	1,242.0
Obligations Under Operating Leases	54.3	61.3
Deferred Credits and Other Noncurrent Liabilities	93.0	73.8
TOTAL NONCURRENT LIABILITIES	7,954.3	6,930.8
TOTAL LIABILITIES	8,840.0	8,242.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	1,555.7	1,553.9
Retained Earnings	2,300.0	2,046.8
Accumulated Other Comprehensive Income (Loss)	(5.7)	(6.5)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,850.0	3,594.2
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,690.0	$ 11,836.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
OPERATING ACTIVITIES		
Net Income	$ 253.2	$ 225.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	342.7	287.1
Deferred Income Taxes	35.1	45.8
Allowance for Equity Funds Used During Construction	(13.2)	(16.7)
Mark-to-Market of Risk Management Contracts	(0.2)	—
Change in Other Noncurrent Assets	(48.4)	(73.4)
Change in Other Noncurrent Liabilities	49.2	17.5
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(57.5)	(40.2)
Materials and Supplies	(39.9)	(2.5)
Accounts Payable	16.0	(10.9)
Accrued Taxes, Net	39.4	29.5
Other Current Assets	1.0	(2.0)
Other Current Liabilities	12.2	(5.0)
Net Cash Flows from Operating Activities	589.6	454.6
INVESTING ACTIVITIES		
Construction Expenditures	(949.8)	(742.4)
Change in Advances to Affiliates, Net	(129.4)	(47.5)
Other Investing Activities	26.7	29.6
Net Cash Flows Used for Investing Activities	(1,052.5)	(760.3)
FINANCING ACTIVITIES		
Capital Contribution from Parent	1.8	—
Issuance of Long-term Debt – Nonaffiliated	1,188.7	444.2
Change in Advances from Affiliates, Net	(26.9)	(67.1)
Retirement of Long-term Debt – Nonaffiliated	(678.6)	(52.2)
Principal Payments for Finance Lease Obligations	(5.1)	(5.0)
Other Financing Activities	0.3	1.0
Net Cash Flows from Financing Activities	480.2	320.9
Net Change in Cash, Cash Equivalents and Restricted Cash	17.3	15.2
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	30.5	28.8
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 47.8	$ 44.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 121.1	$ 110.0
Net Cash Paid (Received) for Income Taxes	10.0	(8.4)
Noncash Acquisitions Under Finance Leases	4.1	3.3
Construction Expenditures Included in Current Liabilities as of September 30,	156.0	134.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of September 30, 2022	2021
	(in millions)	
Plant In Service	$ 12,050.4	$ 10,851.9
Construction Work in Progress	1,644.6	1,507.4
Accumulated Depreciation and Amortization	952.4	730.4
Total Transmission Property, Net	$ 12,742.6	$ 11,628.9

Third Quarter of 2022 Compared to Third Quarter of 2021

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Net Income
(in millions)

Third Quarter of 2021	$ 145.4
Changes in Transmission Revenues:	
Transmission Revenues	41.5
Total Change in Transmission Revenues	41.5
Changes in Expenses and Other:	
Other Operation and Maintenance	(5.7)
Depreciation and Amortization	(11.4)
Taxes Other Than Income Taxes	(7.7)
Interest Income	0.5
Allowance for Equity Funds Used During Construction	4.3
Interest Expense	(6.6)
Total Change in Expenses and Other	(26.6)
Income Tax Expense	(7.6)
Third Quarter of 2022	$ 152.7

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

- **Transmission Revenues** increased $42 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $6 million primarily due to cancelled capital projects.
- **Depreciation and Amortization** expenses increased $11 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $4 million primarily due to higher CWIP.
- **Interest Expense** increased $7 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $8 million primarily due to an increase in pretax book income and a decrease in parent company loss benefit.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Net Income
(in millions)

Nine Months Ended September 30, 2021	$	445.7
Changes in Transmission Revenues:		
Transmission Revenues		79.1
Total Change in Transmission Revenues		79.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(15.5)
Depreciation and Amortization		(37.2)
Taxes Other Than Income Taxes		(24.1)
Interest Income		0.6
Allowance for Equity Funds Used During Construction		1.9
Interest Expense		(15.2)
Total Change in Expenses and Other		(89.5)
Income Tax Expense		(8.7)
Nine Months Ended September 30, 2022	$	426.6

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

- **Transmission Revenues** increased $79 million primarily due to the following:
  - A $122 million increase due to continued investment in transmission assets.

  This increase was partially offset by:
  - A $30 million decrease due to the affiliated annual transmission formula rate true-up. This decrease was offset in Other Operation and Maintenance expense across the other Registrant Subsidiaries.
  - A $13 million decrease due to the non-affiliated annual transmission formula rate true-up.

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

- **Other Operation and Maintenance** expenses increased $16 million primarily due to the following:
  - A $12 million increase in employee-related expenses.
  - A $5 million increase due to cancelled capital projects.
- **Depreciation and Amortization** expenses increased $37 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $24 million primarily due to higher property taxes as a result of increased transmission investment.
- **Interest Expense** increased $15 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $9 million primarily due to a decrease in parent company loss benefit, partially offset by a decrease in pretax book income.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
REVENUES				
Transmission Revenues	$ 89.1	$ 79.2	$ 261.7	$ 241.6
Sales to AEP Affiliates	340.6	297.7	999.5	882.3
Provision for Refund – Affiliated	(9.3)	(0.1)	(65.7)	(17.7)
Provision for Refund – Nonaffiliated	(1.9)	—	(12.2)	(2.3)
Other Revenues	—	0.2	—	0.3
TOTAL REVENUES	418.5	377.0	1,183.3	1,104.2
EXPENSES				
Other Operation	39.6	32.6	94.7	78.1
Maintenance	4.1	5.4	11.2	12.3
Depreciation and Amortization	87.4	76.0	256.2	219.0
Taxes Other Than Income Taxes	68.7	61.0	203.0	178.9
TOTAL EXPENSES	199.8	175.0	565.1	488.3
OPERATING INCOME	218.7	202.0	618.2	615.9
Other Income (Expense):				
Interest Income - Affiliated	0.7	0.2	1.0	0.4
Allowance for Equity Funds Used During Construction	20.3	16.0	51.2	49.3
Interest Expense	(42.7)	(36.1)	(119.7)	(104.5)
INCOME BEFORE INCOME TAX EXPENSE	197.0	182.1	550.7	561.1
Income Tax Expense	44.3	36.7	124.1	115.4
NET INCOME	$ 152.7	$ 145.4	$ 426.6	$ 445.7

AEPTCo is wholly-owned by AEP Transmission Holdco.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2020	$ 2,765.6	$ 1,947.3	$ 4,712.9
Capital Contribution from Member	124.0		124.0
Net Income		151.7	151.7
TOTAL MEMBER'S EQUITY – MARCH 31, 2021	2,889.6	2,099.0	4,988.6
Capital Contribution from Member	60.0		60.0
Net Income		148.6	148.6
TOTAL MEMBER'S EQUITY – JUNE 30, 2021	2,949.6	2,247.6	5,197.2
Dividends Paid to Member		(112.5)	(112.5)
Net Income		145.4	145.4
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2021	$ 2,949.6	$ 2,280.5	$ 5,230.1
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2021	$ 2,949.6	$ 2,426.5	$ 5,376.1
Dividends Paid to Member		(40.0)	(40.0)
Net Income		155.4	155.4
TOTAL MEMBER'S EQUITY – MARCH 31, 2022	2,949.6	2,541.9	5,491.5
Capital Contribution from Member	2.8		2.8
Dividends Paid to Member		(50.0)	(50.0)
Net Income		118.5	118.5
TOTAL MEMBER'S EQUITY – JUNE 30, 2022	2,952.4	2,610.4	5,562.8
Capital Contribution from Member	61.4		61.4
Dividends Paid to Member		(40.0)	(40.0)
Net Income		152.7	152.7
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2022	$ 3,013.8	$ 2,723.1	$ 5,736.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT ASSETS		
Advances to Affiliates	$ 106.7	$ 27.2
Accounts Receivable:		
Customers	73.8	22.5
Affiliated Companies	111.0	96.1
Total Accounts Receivable	184.8	118.6
Materials and Supplies	11.7	9.3
Accrued Tax Benefits	12.3	5.6
Assets Held for Sale	173.7	167.9
Prepayments and Other Current Assets	3.8	2.7
TOTAL CURRENT ASSETS	493.0	331.3
TRANSMISSION PROPERTY		
Transmission Property	11,609.8	10,886.3
Other Property, Plant and Equipment	440.6	427.4
Construction Work in Progress	1,644.6	1,394.8
Total Transmission Property	13,695.0	12,708.5
Accumulated Depreciation and Amortization	952.4	772.8
TOTAL TRANSMISSION PROPERTY – NET	12,742.6	11,935.7
OTHER NONCURRENT ASSETS		
Regulatory Assets	2.6	8.5
Deferred Property Taxes	75.7	245.7
Deferred Charges and Other Noncurrent Assets	5.3	3.2
TOTAL OTHER NONCURRENT ASSETS	83.6	257.4
TOTAL ASSETS	$ 13,319.2	$ 12,524.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT LIABILITIES		
Advances from Affiliates	$ 61.0	$ 124.0
Accounts Payable:		
General	332.1	460.1
Affiliated Companies	121.5	69.9
Long-term Debt Due Within One Year – Nonaffiliated	104.0	104.0
Accrued Taxes	293.0	479.0
Accrued Interest	56.0	28.4
Obligations Under Operating Leases	1.3	0.9
Liabilities Held for Sale	27.6	27.6
Other Current Liabilities	14.8	3.0
TOTAL CURRENT LIABILITIES	1,011.3	1,296.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,782.6	4,239.9
Deferred Income Taxes	1,032.8	962.9
Regulatory Liabilities	698.2	644.1
Obligations Under Operating Leases	1.8	1.3
Deferred Credits and Other Noncurrent Liabilities	55.6	3.2
TOTAL NONCURRENT LIABILITIES	6,571.0	5,851.4
TOTAL LIABILITIES	7,582.3	7,148.3
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	3,013.8	2,949.6
Retained Earnings	2,723.1	2,426.5
TOTAL MEMBER'S EQUITY	5,736.9	5,376.1
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 13,319.2	$ 12,524.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2022	2021
OPERATING ACTIVITIES		
Net Income	$ 426.6	$ 445.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	256.2	219.0
Deferred Income Taxes	60.6	46.8
Allowance for Equity Funds Used During Construction	(51.2)	(49.3)
Property Taxes	170.0	154.0
Change in Other Noncurrent Assets	4.0	2.3
Change in Other Noncurrent Liabilities	55.0	8.3
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(66.4)	(23.6)
Materials and Supplies	(2.4)	(0.5)
Accounts Payable	53.1	(10.7)
Accrued Taxes, Net	(194.0)	(138.8)
Other Current Assets	(1.2)	0.5
Other Current Liabilities	27.2	22.7
Net Cash Flows from Operating Activities	737.5	676.4
INVESTING ACTIVITIES		
Construction Expenditures	(1,059.3)	(1,070.8)
Change in Advances to Affiliates, Net	(84.1)	29.9
Other Investing Activities	(5.3)	(7.9)
Net Cash Flows Used for Investing Activities	(1,148.7)	(1,048.8)
FINANCING ACTIVITIES		
Capital Contribution from Member	64.2	184.0
Issuance of Long-term Debt – Nonaffiliated	540.9	443.7
Change in Advances from Affiliates, Net	(63.9)	(142.8)
Dividends Paid to Member	(130.0)	(112.5)
Net Cash Flows from Financing Activities	411.2	372.4
Net Change in Cash and Cash Equivalents	—	—
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 88.6	$ 75.8
Net Cash Paid for Income Taxes	53.2	37.6
Construction Expenditures Included in Current Liabilities as of September 30,	240.5	206.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions of KWhs)			
Retail:				
Residential	2,553	2,657	8,308	8,524
Commercial	1,566	1,596	4,545	4,483
Industrial	2,211	2,223	6,655	6,590
Miscellaneous	206	206	624	602
Total Retail	6,536	6,682	20,132	20,199
Wholesale	644	1,414	1,269	3,636
Total KWhs	7,180	8,096	21,401	23,835

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in degree days)			
Actual – Heating (a)	4	—	1,372	1,397
Normal – Heating (b)	2	2	1,410	1,404
Actual – Cooling (c)	876	945	1,299	1,330
Normal – Cooling (b)	832	831	1,210	1,214

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

Third Quarter of 2022 Compared to Third Quarter of 2021

Appalachian Power Company and Subsidiaries
Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Net Income
(in millions)

Third Quarter of 2021	$	86.3
Changes in Gross Margin:		
Retail Margins		10.6
Margins from Off-system Sales		3.4
Transmission Revenues		3.4
Other Revenues		2.7
Total Change in Gross Margin		20.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(9.2)
Asset Impairments and Other Related Charges - Coal Fired Generation		(24.9)
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset		37.0
Depreciation and Amortization		(7.5)
Taxes Other Than Income Taxes		(1.7)
Interest Income		2.4
Allowance for Equity Funds Used During Construction		(2.1)
Non-Service Cost Components of Net Periodic Benefit Cost		2.6
Interest Expense		(8.9)
Total Change in Expenses and Other		(12.3)
Income Tax Expense		(1.4)
Third Quarter of 2022	$	92.7

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

- **Retail Margins** increased $11 million primarily due to the following:
  - A $20 million increase due to rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.

  This increase was partially offset by:
  - A $6 million decrease in weather-normalized margins primarily driven by decreases in the residential and industrial classes.
  - A $5 million decrease in weather-related usage primarily driven by a 7% decrease in cooling degree days.
- **Margins from Off-System Sales** increased $3 million primarily due to increased generation and strong market pricing.
- **Transmission Revenues** increased $3 million primarily due to continued investment in transmission assets.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $9 million primarily due to the following:
  - A $6 million increase in distribution expenses primarily due to storm restoration expenses.
  - A $2 million increase in renewable energy credits and compliance expenses associated with the Virginia Clean Economy Act. This increase was offset in Retail Margins above.
- **Asset Impairments and Other Related Charges - Coal Fired Generation** increased $25 million due to a write-off of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to the 2017-2019 Virginia Triennial Review.
- **Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset** increased $37 million due to the establishment of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion and resulting under-earning during the 2017-2019 Triennial Review.
- **Depreciation and Amortization** expenses increased $8 million primarily due to a higher depreciable base.
- **Interest Expense** increased $9 million primarily due to higher long-term debt balances and higher interest rates.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Appalachian Power Company and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Net Income
(in millions)

Nine Months Ended September 30, 2021	$	275.1
Changes in Gross Margin:		
Retail Margins		130.2
Margins from Off-system Sales		(0.6)
Transmission Revenues		21.1
Other Revenues		7.2
Total Change in Gross Margin		157.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(102.1)
Asset Impairments and Other Related Charges - Coal Fired Generation		(24.9)
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset		37.0
Depreciation and Amortization		(24.4)
Taxes Other Than Income Taxes		(4.3)
Interest Income		2.2
Allowance for Equity Funds Used During Construction		(5.3)
Non-Service Cost Components of Net Periodic Benefit Cost		7.6
Interest Expense		(10.5)
Total Change in Expenses and Other		(124.7)
Income Tax Expense		(5.2)
Nine Months Ended September 30, 2022	$	303.1

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 $130 million primarily due to the following:
  - A $104 million increase due to rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.
  - An $18 million increase due to lower customer refunds related to Tax Reform. This increase was offset in Income Tax Expense below.
  - A $13 million increase in weather-normalized margins primarily driven by increases in the residential and commercial classes.

  These increases were partially offset by:
  - A $6 million decrease in weather-related usage primarily driven by a 2% decrease in cooling degree days and a 2% decrease in heating degree days.
- **Transmission Revenues** increased $21 million primarily due to the following:
  - An $11 million increase due to continued investment in transmission assets.
  - A $10 million increase due to transmission formula rate true-up activity.
- **Other Revenues** increased $7 million primarily due to business development revenue. This increase was partially offset in Other Operation and Maintenance expenses below.

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

- **Other Operation and Maintenance** expenses increased $102 million primarily due to the following:
  - A $63 million increase in transmission expenses primarily due to an $80 million increase in recoverable PJM expenses, partially offset by an $11 million decrease in transmission formula rate true-up activity. These items were primarily offset in Retail Margins above.
  - A $24 million increase in maintenance expenses at various generation plants.
  - A $16 million increase in distribution expenses primarily related to storm restoration costs.
  - A $7 million increase in employee-related expenses.

  These increases were partially offset by:
  - A $13 million decrease due to gains from the sale of land in 2022.
- **Asset Impairments and Other Related Charges - Coal Fired Generation** increased $25 million due to a write-off of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to the 2017-2019 Virginia Triennial Review.
- **Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset** increased $37 million due to the establishment of a regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion and resulting under-earning during the 2017-2019 Triennial Review.
- **Depreciation and Amortization** expenses increased $24 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $4 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Allowance for Equity Funds Used During Construction** decreased $5 million primarily due to a lower AFUDC base and a decrease in AFUDC equity rates.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $8 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $11 million primarily due to higher long-term debt balances and higher interest rates.
- **Income Tax Expense** increased $5 million primarily due to an increase in pretax book income and a decrease in amortization of Excess ADIT, partially offset by a decrease in state taxes and a favorable one-time adjustment recognized in 2022. The decrease in amortization of Excess ADIT was partially offset in Retail Margins above.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
REVENUES				
Electric Generation, Transmission and Distribution	$ 818.4	$ 748.5	$ 2,370.4	$ 2,149.2
Sales to AEP Affiliates	67.6	52.4	187.6	140.6
Other Revenues	2.9	3.1	11.8	8.2
TOTAL REVENUES	888.9	804.0	2,569.8	2,298.0
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	318.0	253.2	834.2	720.3
Other Operation	182.0	173.0	514.0	442.1
Maintenance	69.3	69.1	214.6	184.4
Asset Impairments and Other Related Charges - Coal Fired Generation	24.9	—	24.9	—
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—	(37.0)	—
Depreciation and Amortization	142.9	135.4	431.0	406.6
Taxes Other Than Income Taxes	41.5	39.8	121.0	116.7
TOTAL EXPENSES	741.6	670.5	2,102.7	1,870.1
OPERATING INCOME	147.3	133.5	467.1	427.9
Other Income (Expense):				
Interest Income	2.6	0.2	3.0	0.8
Allowance for Equity Funds Used During Construction	2.2	4.3	6.8	12.1
Non-Service Cost Components of Net Periodic Benefit Cost	7.3	4.7	21.8	14.2
Interest Expense	(61.7)	(52.8)	(171.1)	(160.6)
INCOME BEFORE INCOME TAX EXPENSE	97.7	89.9	327.6	294.4
Income Tax Expense	5.0	3.6	24.5	19.3
NET INCOME	$ 92.7	$ 86.3	$ 303.1	$ 275.1

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Net Income	$ 92.7	$ 86.3	$ 303.1	$ 275.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $0 for the Three Months Ended September 30, 2022 and 2021, Respectively, and $(0.2) and $2.3 for Nine Months Ended September 30, 2022 and 2021, Respectively	(0.2)	(0.3)	(0.6)	8.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.3) and $(0.2) for the Three Months Ended September 30, 2022 and 2021, Respectively, and $(0.9) and $(0.8) for the Nine Months Ended September 30, 2022 and 2021, Respectively	(1.1)	(1.0)	(3.2)	(3.1)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(1.3)	(1.3)	(3.8)	5.4
TOTAL COMPREHENSIVE INCOME	$ 91.4	$ 85.0	$ 299.3	$ 280.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2020	$ 260.4	$ 1,828.7	$ 2,248.0	$ 7.2	$ 4,344.3
Common Stock Dividends			(12.5)		(12.5)
Net Income			122.5		122.5
Other Comprehensive Income				7.9	7.9
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2021	260.4	1,828.7	2,358.0	15.1	4,462.2
Common Stock Dividends			(12.5)		(12.5)
Net Income			66.3		66.3
Other Comprehensive Loss				(1.2)	(1.2)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2021	260.4	1,828.7	2,411.8	13.9	4,514.8
Common Stock Dividends			(12.5)		(12.5)
Net Income			86.3		86.3
Other Comprehensive Loss				(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2021	$ 260.4	$ 1,828.7	$ 2,485.6	$ 12.6	$ 4,587.3
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2021	$ 260.4	$ 1,828.7	$ 2,534.4	$ 24.4	$ 4,647.9
Common Stock Dividends			(18.8)		(18.8)
Net Income			120.2		120.2
Other Comprehensive Loss				(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2022	260.4	1,828.7	2,635.8	23.1	4,748.0
Capital Contribution from Parent		2.8			2.8
Common Stock Dividends			(18.7)		(18.7)
Net Income			90.2		90.2
Other Comprehensive Loss				(1.2)	(1.2)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2022	260.4	1,831.5	2,707.3	21.9	4,821.1
Capital Contribution from Parent		1.5			1.5
Net Income			92.7		92.7
Other Comprehensive Loss				(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2022	$ 260.4	$ 1,833.0	$ 2,800.0	$ 20.6	$ 4,914.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6.7	$ 2.5
Restricted Cash for Securitized Funding	7.4	17.6
Advances to Affiliates	182.1	20.8
Accounts Receivable:		
Customers	133.7	158.5
Affiliated Companies	92.6	129.9
Accrued Unbilled Revenues	49.6	54.0
Miscellaneous	0.3	0.2
Allowance for Uncollectible Accounts	(1.5)	(1.6)
Total Accounts Receivable	274.7	341.0
Fuel	118.6	67.1
Materials and Supplies	120.4	109.8
Risk Management Assets	106.8	42.0
Accrued Tax Benefits	106.7	38.1
Regulatory Asset for Under-Recovered Fuel Costs	404.0	201.3
Margin Deposits	6.1	71.8
Prepayments and Other Current Assets	17.5	13.3
TOTAL CURRENT ASSETS	1,351.0	925.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,731.0	6,683.9
Transmission	4,445.2	4,322.4
Distribution	4,849.1	4,683.3
Other Property, Plant and Equipment	853.3	696.6
Construction Work in Progress	617.7	469.9
Total Property, Plant and Equipment	17,496.3	16,856.1
Accumulated Depreciation and Amortization	5,332.7	5,051.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	12,163.6	11,804.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	970.3	757.6
Securitized Assets	165.9	185.1
Employee Benefits and Pension Assets	231.6	220.5
Operating Lease Assets	61.2	66.9
Deferred Charges and Other Noncurrent Assets	99.4	129.2
TOTAL OTHER NONCURRENT ASSETS	1,528.4	1,359.3
TOTAL ASSETS	$ 15,043.0	$ 14,088.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2022 and December 31, 2021
(Unaudited)

	September 30, 2022	December 31, 2021
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 199.3
Accounts Payable:		
General	374.6	262.2
Affiliated Companies	168.2	118.6
Long-term Debt Due Within One Year – Nonaffiliated	351.8	480.7
Customer Deposits	76.8	73.9
Accrued Taxes	89.4	119.7
Accrued Interest	84.1	47.9
Obligations Under Operating Leases	14.4	15.1
Other Current Liabilities	116.8	98.5
TOTAL CURRENT LIABILITIES	1,276.1	1,415.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	5,158.0	4,458.2
Deferred Income Taxes	1,937.0	1,804.7
Regulatory Liabilities and Deferred Investment Tax Credits	1,218.4	1,238.8
Asset Retirement Obligations	418.8	394.9
Employee Benefits and Pension Obligations	40.2	41.5
Obligations Under Operating Leases	47.3	52.4
Deferred Credits and Other Noncurrent Liabilities	33.2	34.6
TOTAL NONCURRENT LIABILITIES	8,852.9	8,025.1
TOTAL LIABILITIES	10,129.0	9,441.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,833.0	1,828.7
Retained Earnings	2,800.0	2,534.4
Accumulated Other Comprehensive Income (Loss)	20.6	24.4
TOTAL COMMON SHAREHOLDER'S EQUITY	4,914.0	4,647.9
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 15,043.0	$ 14,088.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2022	2021
OPERATING ACTIVITIES		
Net Income	$ 303.1	$ 275.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	431.0	406.6
Deferred Income Taxes	70.7	(12.0)
Asset Impairments and Other Related Charges - Coal Fired Generation	24.9	—
Allowance for Equity Funds Used During Construction	(6.8)	(12.1)
Mark-to-Market of Risk Management Contracts	(65.6)	(26.8)
Deferred Fuel Over/Under-Recovery, Net	(400.2)	(43.9)
Establishment of 2017-2019 Virginia Triennial Review Regulatory Asset	(37.0)	—
Change in Other Noncurrent Assets	(15.2)	(39.2)
Change in Other Noncurrent Liabilities	39.7	20.2
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	68.7	38.1
Fuel, Materials and Supplies	(61.7)	126.3
Margin Deposits	65.8	(15.8)
Accounts Payable	141.4	26.5
Accrued Taxes, Net	(98.9)	(48.0)
Other Current Assets	(4.2)	(4.9)
Other Current Liabilities	42.2	0.5
Net Cash Flows from Operating Activities	497.9	690.6
INVESTING ACTIVITIES		
Construction Expenditures	(707.4)	(586.4)
Change in Advances to Affiliates, Net	(161.3)	(163.8)
Other Investing Activities	34.9	12.4
Net Cash Flows Used for Investing Activities	(833.8)	(737.8)
FINANCING ACTIVITIES		
Capital Contribution from Parent	4.3	—
Issuance of Long-term Debt – Nonaffiliated	698.2	494.0
Change in Advances from Affiliates, Net	(199.3)	(18.6)
Retirement of Long-term Debt – Nonaffiliated	(130.4)	(393.0)
Principal Payments for Finance Lease Obligations	(5.9)	(5.8)
Dividends Paid on Common Stock	(37.5)	(37.5)
Other Financing Activities	0.5	0.5
Net Cash Flows from Financing Activities	329.9	39.6
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(6.0)	(7.6)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	20.1	22.7
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 14.1	$ 15.1
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 128.3	$ 124.2
Net Cash Paid for Income Taxes	14.2	52.6
Noncash Acquisitions Under Finance Leases	1.0	1.3
Construction Expenditures Included in Current Liabilities as of September 30,	160.4	92.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions of KWhs)			
Retail:				
Residential	1,532	1,531	4,320	4,244
Commercial	1,326	1,267	3,610	3,481
Industrial	1,926	1,853	5,638	5,542
Miscellaneous	12	13	39	42
Total Retail	4,796	4,664	13,607	13,309
Wholesale	1,707	1,610	4,892	5,055
Total KWhs	6,503	6,274	18,499	18,364

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in degree days)			
Actual – Heating (a)	17	2	2,525	2,343
Normal – Heating (b)	8	9	2,421	2,417
Actual – Cooling (c)	590	679	934	1,004
Normal – Cooling (b)	580	581	842	848

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

Third Quarter of 2022 Compared to Third Quarter of 2021

Indiana Michigan Power Company and Subsidiaries
Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Net Income
(in millions)

Third Quarter of 2021	$	104.1
Changes in Gross Margin:		
Retail Margins		10.1
Margins from Off-system Sales		0.2
Transmission Revenues		1.2
Other Revenues		1.6
Total Change in Gross Margin		13.1
Changes in Expenses and Other:		
Other Operation and Maintenance		1.2
Depreciation and Amortization		(21.0)
Taxes Other Than Income Taxes		5.4
Other Income		(0.1)
Non-Service Cost Components of Net Periodic Benefit Cost		2.2
Interest Expense		(1.0)
Total Change in Expenses and Other		(13.3)
Income Tax Expense		(9.8)
Third Quarter of 2022	$	94.1

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 $10 million primarily due to the following:
  - A $15 million increase primarily due to an increase in rider revenues. This increase was partially offset in other expense items below.

 This increase was partially offset by:
  - A $7 million decrease in weather-related usage primarily due to a 13% decrease in cooling degree days.

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

- **Other Operation and Maintenance** expenses decreased $1 million primarily due to the following:
  - A $17 million decrease in steam generation expenses primarily due to the modification of the Rockport Plant, Unit 2 lease, which resulted in a change in lease classification from an operating lease to a finance lease in December 2021. This decrease was partially offset in Depreciation and Amortization expenses below.

This decrease was partially offset by:

- A $10 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses. This increase was partially offset in Retail Margins above.
- A $6 million increase in nuclear expenses at Cook Plant primarily due to refueling outage expenses.

- **Depreciation and Amortization** expenses increased $21 million primarily due to the modification of the Rockport Plant, Unit 2 lease, which resulted in a change in lease classification from an operating lease to a finance lease in December 2021 and a higher depreciable base. The increase resulting from the lease modification was partially offset in Other Operation and Maintenance expenses above.
- **Taxes Other Than Income Taxes** decreased $5 million primarily due to the repeal of the Indiana Utility Receipts Tax in July 2022. This decrease was partially offset in Retail Margins above.
- **Income Tax Expense** increased $10 million primarily due to a decrease in amortization of Excess ADIT, a decrease in the benefit from investment tax credit amortization, and a decrease in parent company loss benefit.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Indiana Michigan Power Company and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Net Income
(in millions)

Nine Months Ended September 30, 2021	$	232.1
Changes in Gross Margin:		
Retail Margins		52.4
Margins from Off-system Sales		0.4
Transmission Revenues		11.3
Other Revenues		6.2
Total Change in Gross Margin		70.3
Changes in Expenses and Other:		
Other Operation and Maintenance		29.2
Depreciation and Amortization		(71.5)
Taxes Other Than Income Taxes		7.6
Other Income		(1.5)
Non-Service Cost Components of Net Periodic Benefit Cost		6.5
Interest Expense		(5.9)
Total Change in Expenses and Other		(35.6)
Income Tax Expense		(16.0)
Nine Months Ended September 30, 2022	$	250.8

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

- **Retail Margins** increased $52 million primarily due to the following:
  - A $43 million increase due to increased rider revenues partially offset by lower wholesale true-ups. This increase was partially offset in other expense items below.
  - A $6 million increase in weather-normalized retail margins primarily in the commercial class.
- **Transmission Revenues** increased $11 million primarily due to the following:
  - A $7 million increase due to transmission formula rate true-up activity.
  - A $4 million increase due to continued investment in transmission assets.
- **Other Revenues** increased $6 million primarily due to a gain on sale of allowances and economic hedging activities. The gain on sale of allowances was partially offset in Retail Margins above.

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

- **Other Operation and Maintenance** expenses decreased $29 million primarily due to the following:
  - A $54 million decrease in steam generation expenses primarily due to the modification of the Rockport Plant, Unit 2 lease, which resulted in a change in lease classification from an operating lease to a finance lease in December 2021. This decrease was partially offset in Depreciation and Amortization expenses below.
  - A $4 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2022.

These decreases were partially offset by:

- A $14 million increase in nuclear expenses at Cook Plant primarily due to refueling outage expenses.
- A $13 million increase in transmission expenses primarily due to the following:
  - A $31 million increase in recoverable PJM expenses. These expenses were offset in Retail Margins above.

  This increase was partially offset by:
  - A $9 million decrease in transmission vegetation management expenses.
  - A $7 million decrease in transmission formula rate true-up activity.

- **Depreciation and Amortization** expenses increased $72 million primarily due to the modification of the Rockport Plant, Unit 2 lease, which resulted in a change in lease classification from an operating lease to a finance lease in December 2021, and a higher depreciable base. The increase resulting from the lease modification was partially offset in Other Operation and Maintenance expenses above.
- **Taxes Other Than Income Taxes** decreased $8 million primarily due to the repeal of the Indiana Utility Receipts Tax in July 2022. This decrease was partially offset in Retail Margins above.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $7 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** increased $6 million primarily due to a debt issuance in April 2021.
- **Income Tax Expense** increased $16 million primarily due to an increase in pretax book income, a decrease in the benefit from investment tax credit amortization, and a decrease in parent company loss benefit.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
REVENUES				
Electric Generation, Transmission and Distribution	$ 695.7	$ 618.2	$ 1,912.1	$ 1,735.1
Sales to AEP Affiliates	2.0	1.1	11.1	2.6
Other Revenues – Affiliated	13.3	14.7	38.4	41.2
Other Revenues – Nonaffiliated	4.4	1.7	10.0	5.1
TOTAL REVENUES	715.4	635.7	1,971.6	1,784.0
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	150.6	88.6	367.2	261.8
Purchased Electricity from AEP Affiliates	67.9	63.3	184.6	172.7
Other Operation	162.4	167.5	450.9	482.4
Maintenance	55.9	52.0	167.7	165.4
Depreciation and Amortization	131.6	110.6	400.2	328.7
Taxes Other Than Income Taxes	22.4	27.8	76.2	83.8
TOTAL EXPENSES	590.8	509.8	1,646.8	1,494.8
OPERATING INCOME	124.6	125.9	324.8	289.2
Other Income (Expense):				
Other Income	2.4	2.5	7.4	8.9
Non-Service Cost Components of Net Periodic Benefit Cost	6.3	4.1	18.8	12.3
Interest Expense	(31.2)	(30.2)	(92.5)	(86.6)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	102.1	102.3	258.5	223.8
Income Tax Expense (Benefit)	8.0	(1.8)	7.7	(8.3)
NET INCOME	$ 94.1	$ 104.1	$ 250.8	$ 232.1

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Net Income	$ 94.1	$ 104.1	$ 250.8	$ 232.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended September 30, 2022 and 2021, Respectively, and $0.3 and $0.3 for the Nine Months Ended September 30, 2022 and 2021, Respectively	0.4	0.4	1.2	1.3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $0 for the Three Months Ended September 30, 2022 and 2021, Respectively, and $(0.1) and $0 for the Nine Months Ended September 30, 2022 and 2021, Respectively	(0.1)	—	(0.3)	(0.1)
TOTAL OTHER COMPREHENSIVE INCOME	0.3	0.4	0.9	1.2
TOTAL COMPREHENSIVE INCOME	$ 94.4	$ 104.5	$ 251.7	$ 233.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2020	$ 56.6	$ 980.9	$ 1,718.7	$ (7.0)	$ 2,749.2
Common Stock Dividends			(25.0)		(25.0)
Net Income			70.8		70.8
Other Comprehensive Income				0.5	0.5
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2021	56.6	980.9	1,764.5	(6.5)	2,795.5
Common Stock Dividends			(75.0)		(75.0)
Net Income			57.2		57.2
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2021	56.6	980.9	1,746.7	(6.2)	2,778.0
Common Stock Dividends			(75.0)		(75.0)
Net Income			104.1		104.1
Other Comprehensive Income				0.4	0.4
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2021	$ 56.6	$ 980.9	$ 1,775.8	$ (5.8)	$ 2,807.5
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2021	$ 56.6	$ 980.9	$ 1,748.5	$ (1.3)	$ 2,784.7
Common Stock Dividends			(25.0)		(25.0)
Net Income			89.5		89.5
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2022	56.6	980.9	1,813.0	(1.0)	2,849.5
Capital Contribution from Parent		1.3			1.3
Common Stock Dividends			(25.0)		(25.0)
Net Income			67.2		67.2
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2022	56.6	982.2	1,855.2	(0.7)	2,893.3
Capital Contribution from Parent		0.6			0.6
Common Stock Dividends			(20.0)		(20.0)
Net Income			94.1		94.1
Other Comprehensive Income				0.3	0.3
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2022	$ 56.6	$ 982.8	$ 1,929.3	$ (0.4)	$ 2,968.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 25.8	$ 1.3
Advances to Affiliates	22.6	21.5
Accounts Receivable:		
Customers	40.8	40.6
Affiliated Companies	72.7	78.2
Accrued Unbilled Revenues	0.4	—
Miscellaneous	3.4	2.5
Allowance for Uncollectible Accounts	—	(0.1)
Total Accounts Receivable	117.3	121.2
Fuel	49.5	56.8
Materials and Supplies	179.4	175.2
Regulatory Asset for Under-Recovered Fuel Costs	25.4	6.4
Prepayments and Other Current Assets	50.0	57.0
TOTAL CURRENT ASSETS	470.0	439.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,601.6	5,531.8
Transmission	1,823.9	1,783.1
Distribution	2,955.9	2,800.1
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	854.6	792.9
Construction Work in Progress	314.7	302.8
Total Property, Plant and Equipment	11,550.7	11,210.7
Accumulated Depreciation, Depletion and Amortization	4,161.3	3,899.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,389.4	7,310.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	422.5	410.9
Spent Nuclear Fuel and Decommissioning Trusts	3,130.5	3,867.0
Operating Lease Assets	51.9	63.5
Deferred Charges and Other Noncurrent Assets	278.5	316.5
TOTAL OTHER NONCURRENT ASSETS	3,883.4	4,657.9
TOTAL ASSETS	$ 11,742.8	$ 12,408.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2022 and December 31, 2021
(dollars in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT LIABILITIES		
Advances from Affiliates	$ 104.9	$ 93.3
Accounts Payable:		
General	187.3	174.4
Affiliated Companies	94.0	94.9
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2022 and December 31, 2021 Amounts Include $68.8 and $65, Respectively, Related to DCC Fuel)	320.9	67.0
Customer Deposits	43.0	45.2
Accrued Taxes	76.9	106.5
Accrued Interest	24.5	37.0
Obligations Under Finance Leases	94.1	130.5
Obligations Under Operating Leases	11.3	15.5
Regulatory Liability for Over-Recovered Fuel Costs	—	1.5
Other Current Liabilities	92.5	128.2
TOTAL CURRENT LIABILITIES	1,049.4	894.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,885.8	3,128.0
Deferred Income Taxes	1,143.6	1,100.2
Regulatory Liabilities and Deferred Investment Tax Credits	1,577.0	2,447.9
Asset Retirement Obligations	2,009.8	1,946.2
Obligations Under Operating Leases	41.6	48.9
Deferred Credits and Other Noncurrent Liabilities	67.3	58.3
TOTAL NONCURRENT LIABILITIES	7,725.1	8,729.5
TOTAL LIABILITIES	8,774.5	9,623.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	982.8	980.9
Retained Earnings	1,929.3	1,748.5
Accumulated Other Comprehensive Income (Loss)	(0.4)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,968.3	2,784.7
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 11,742.8	$ 12,408.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2022	2021
OPERATING ACTIVITIES		
Net Income	$ 250.8	$ 232.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	400.2	328.7
Rockport Plant, Unit 2 Operating Lease Amortization	—	51.1
Deferred Income Taxes	(15.8)	(36.6)
Deferral of Incremental Nuclear Refueling Outage Expenses, Net	(35.2)	(2.5)
Allowance for Equity Funds Used During Construction	(7.9)	(9.7)
Mark-to-Market of Risk Management Contracts	(13.2)	0.5
Amortization of Nuclear Fuel	63.1	61.9
Deferred Fuel Over/Under-Recovery, Net	(20.5)	(18.0)
Change in Other Noncurrent Assets	12.5	7.3
Change in Other Noncurrent Liabilities	42.1	(10.2)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5.3	18.2
Fuel, Materials and Supplies	3.1	43.0
Accounts Payable	19.6	20.1
Accrued Taxes, Net	(17.0)	(20.3)
Rockport Plant, Unit 2 Operating Lease Payments	—	(36.9)
Other Current Assets	19.3	(0.7)
Other Current Liabilities	(63.6)	(28.0)
Net Cash Flows from Operating Activities	642.8	600.0
INVESTING ACTIVITIES		
Construction Expenditures	(407.4)	(370.2)
Change in Advances to Affiliates, Net	(1.1)	(67.3)
Purchases of Investment Securities	(1,854.8)	(1,586.3)
Sales of Investment Securities	1,818.4	1,556.6
Acquisitions of Nuclear Fuel	(91.9)	(63.2)
Other Investing Activities	8.0	12.9
Net Cash Flows Used for Investing Activities	(528.8)	(517.5)
FINANCING ACTIVITIES		
Capital Contribution from Parent	1.9	—
Issuance of Long-term Debt – Nonaffiliated	72.8	507.0
Change in Advances from Affiliates, Net	11.6	(103.0)
Retirement of Long-term Debt – Nonaffiliated	(64.5)	(307.2)
Principal Payments for Finance Lease Obligations	(41.6)	(4.9)
Dividends Paid on Common Stock	(70.0)	(175.0)
Other Financing Activities	0.3	0.5
Net Cash Flows Used for Financing Activities	(89.5)	(82.6)
Net Increase (Decrease) in Cash and Cash Equivalents	24.5	(0.1)
Cash and Cash Equivalents at Beginning of Period	1.3	3.3
Cash and Cash Equivalents at End of Period	$ 25.8	$ 3.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 101.6	$ 93.9
Net Cash Paid (Received) for Income Taxes	(4.1)	11.8
Noncash Acquisitions Under Finance Leases	0.8	3.1
Construction Expenditures Included in Current Liabilities as of September 30,	68.1	59.0
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	8.5	0.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

OHIO POWER COMPANY AND SUBSIDIARIES

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions of KWhs)			
Retail:				
Residential	3,954	4,096	11,146	11,261
Commercial	4,295	4,112	11,996	11,282
Industrial	3,561	3,633	10,688	10,769
Miscellaneous	25	25	79	80
Total Retail (a)	11,835	11,866	33,909	33,392
Wholesale (b)	587	643	1,723	1,691
Total KWhs	12,422	12,509	35,632	35,083

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

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in degree days)			
Actual – Heating (a)	8	1	2,078	1,993
Normal – Heating (b)	5	5	2,077	2,071
Actual – Cooling (c)	755	787	1,115	1,148
Normal – Cooling (b)	688	689	989	996

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

Third Quarter of 2022 Compared to Third Quarter of 2021

Ohio Power Company and Subsidiaries
Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Net Income
(in millions)

Third Quarter of 2021	$	56.4
Changes in Gross Margin:		
Retail Margins		31.0
Margins from Off-system Sales		21.8
Transmission Revenues		2.1
Other Revenues		(12.6)
Total Change in Gross Margin		42.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(30.7)
Depreciation and Amortization		6.2
Taxes Other Than Income Taxes		(5.0)
Carrying Costs Income		(0.1)
Allowance for Equity Funds Used During Construction		1.9
Non-Service Cost Components of Net Periodic Benefit Cost		1.9
Interest Expense		3.1
Total Change in Expenses and Other		(22.7)
Income Tax Expense		(4.1)
Third Quarter of 2022	$	71.9

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

- **Retail Margins** increased $31 million primarily due to the following:
  - A $21 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $4 million increase in weather-related usage primarily due to the end of decoupling.
- **Margins from Off-system Sales** increased $22 million primarily due to the following:
  - A $17 million increase in off-system sales at OVEC due to higher market prices. This increase was offset in Retail Margins above and Other Revenues below.
  - A $5 million increase in deferrals of OVEC costs. This increase was offset in Retail Margins above and Other Revenues below.
- **Other Revenues** decreased $13 million primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs. This decrease was offset in Retail Margins and Margins from Off-system Sales above.

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

- **Other Operation and Maintenance** expenses increased $31 million primarily due to the following:
  - A $14 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses. This increase was offset in Retail Margins above.

- A $5 million increase in remitted Universal Service Fund 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 $5 million increase in recoverable distribution expenses primarily related to vegetation management. This increase was offset in Retail Margins above.

- **Depreciation and Amortization** expenses decreased $6 million primarily due to a decrease in recoverable Distribution Investment Rider depreciable expenses. This decrease was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $5 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Interest Expense** decreased $3 million primarily due to the retirement of a higher rate bond partially offset by the issuance of a lower rate bond in 2021.
- **Income Tax Expense** increased $4 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Ohio Power Company and Subsidiaries
Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Net Income
(in millions)

Nine Months Ended September 30, 2021	$	198.6
Changes in Gross Margin:		
Retail Margins		138.7
Margins from Off-system Sales		47.8
Transmission Revenues		(3.2)
Other Revenues		(28.8)
Total Change in Gross Margin		154.5
Changes in Expenses and Other:		
Other Operation and Maintenance		(125.6)
Depreciation and Amortization		11.7
Taxes Other Than Income Taxes		(12.8)
Interest Income		0.3
Carrying Costs Income		(0.9)
Allowance for Equity Funds Used During Construction		2.7
Non-Service Cost Components of Net Periodic Benefit Cost		5.6
Interest Expense		7.4
Total Change in Expenses and Other		(111.6)
Income Tax Expense		(12.4)
Equity Earnings of Unconsolidated Subsidiaries		0.8
Nine Months Ended September 30, 2022	$	229.9

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

- **Retail Margins** increased $139 million primarily due to the following:
  - An $85 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $25 million increase due to various rider revenues. This increase was partially offset in Margins from Off-system Sales, Other Revenues, and other expense items below.
  - A $12 million increase in weather-normalized margins primarily from the commercial class, partially offset by the residential and industrial classes.
  - An $8 million increase in weather-related usage primarily due to the end of decoupling.
- **Margins from Off-system Sales** increased $48 million primarily due to the following:
  - A $54 million increase in off-system sales at OVEC due to higher market prices and volume. This increase was offset in Retail Margins above and Other Revenues below.

  This increase was partially offset by:
  - A $6 million decrease in deferrals of OVEC costs. This decrease was offset in Retail Margins above and Other Revenues below.
- **Transmission Revenues** decreased $3 million primarily due to the following:
  - An $11 million decrease due to formula rate true-up activity.

This decrease was partially offset by:

- A $7 million increase due to continued investment in transmission assets.

- **Other Revenues** decreased $29 million primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs. This decrease was offset in Retail Margins and Margins from Off-system Sales above.

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

- **Other Operation and Maintenance** expenses increased $126 million primarily due to the following:
  - A $67 million increase in transmission expenses primarily due to the following:
    - A $67 million increase in recoverable PJM expenses. This increase was offset in Retail Margins above.
    - A $6 million increase in transmission vegetation management expenses.

    These increases were partially offset by:
    - A $10 million decrease in transmission formula rate true-up activity.
  - A $19 million increase in bad debt-related expenses, including $8 million in 2022 due to Bad Debt Rider over-recovery. This increase was offset in Retail Margins above.
  - A $15 million increase in recoverable distribution expenses primarily related to vegetation management. This increase was offset in Retail Margins above.
  - A $14 million increase in remitted Universal Service Fund 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 $10 million increase in employee-related expenses.
- **Depreciation and Amortization** expenses decreased $12 million primarily due to the following:
  - A $6 million decrease in recoverable smart grid depreciable expenses. This decrease was offset in Retail Margins above.
  - A $6 million decrease in recoverable Distributions Investment Rider depreciable expenses. This decrease was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $13 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $6 million primarily due to an increase in discount rates, an increase in the expected return on plan assets and favorable plan returns in 2021.
- **Interest Expense** decreased $7 million primarily due to the retirement of a higher rate bond partially offset by the issuance of a lower rate bond in 2021.
- **Income Tax Expense** increased $12 million primarily due to an increase in pretax book income and a favorable 2021 discrete tax adjustment that did not recur during 2022.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
REVENUES				
Electricity, Transmission and Distribution	$ 1,015.2	$ 761.0	$ 2,656.6	$ 2,167.8
Sales to AEP Affiliates	4.0	4.3	11.6	21.9
Other Revenues	2.1	2.4	6.0	6.8
TOTAL REVENUES	1,021.3	767.7	2,674.2	2,196.5
EXPENSES				
Purchased Electricity for Resale	399.5	184.7	875.0	513.6
Purchased Electricity from AEP Affiliates	—	3.5	9.8	48.0
Other Operation	267.3	245.1	728.2	622.9
Maintenance	47.8	39.3	136.7	116.4
Depreciation and Amortization	70.7	76.9	216.9	228.6
Taxes Other Than Income Taxes	131.0	126.0	379.0	366.2
TOTAL EXPENSES	916.3	675.5	2,345.6	1,895.7
OPERATING INCOME	105.0	92.2	328.6	300.8
Other Income (Expense):				
Interest Income	0.2	0.2	0.8	0.5
Carrying Costs Income	—	0.1	0.2	1.1
Allowance for Equity Funds Used During Construction	3.9	2.0	10.3	7.6
Non-Service Cost Components of Net Periodic Benefit Cost	5.6	3.7	16.6	11.0
Interest Expense	(29.8)	(32.9)	(88.8)	(96.2)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	84.9	65.3	267.7	224.8
Income Tax Expense	13.0	8.9	38.6	26.2
Equity Earnings of Unconsolidated Subsidiaries	—	—	0.8	—
NET INCOME	$ 71.9	$ 56.4	$ 229.9	$ 198.6

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 321.2	$ 838.8	$ 1,532.7	$ 2,692.7
Common Stock Dividends			(21.9)	(21.9)
Net Income			68.2	68.2
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2021	321.2	838.8	1,579.0	2,739.0
Common Stock Dividends			(21.9)	(21.9)
Net Income			74.0	74.0
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2021	321.2	838.8	1,631.1	2,791.1
Common Stock Dividends			(28.1)	(28.1)
Net Income			56.4	56.4
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2021	$ 321.2	$ 838.8	$ 1,659.4	$ 2,819.4
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2021	$ 321.2	$ 838.8	$ 1,686.3	$ 2,846.3
Common Stock Dividends			(15.0)	(15.0)
Net Income			83.2	83.2
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2022	321.2	838.8	1,754.5	2,914.5
Capital Contribution from Parent		0.7		0.7
Common Stock Dividends			(15.0)	(15.0)
Net Income			74.8	74.8
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2022	321.2	839.5	1,814.3	2,975.0
Capital Contribution from Parent		0.3		0.3
Common Stock Dividends			(15.0)	(15.0)
Net Income			71.9	71.9
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2022	$ 321.2	$ 839.8	$ 1,871.2	$ 3,032.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 10.2	$ 3.0
Advances to Affiliates	—	42.0
Accounts Receivable:		
Customers	60.3	71.6
Affiliated Companies	105.9	71.8
Accrued Unbilled Revenues	14.4	1.3
Miscellaneous	0.2	5.9
Allowance for Uncollectible Accounts	(0.1)	(0.6)
Total Accounts Receivable	180.7	150.0
Materials and Supplies	97.8	74.1
Renewable Energy Credits	33.6	30.5
Prepayments and Other Current Assets	27.2	27.9
TOTAL CURRENT ASSETS	349.5	327.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	3,070.4	2,992.8
Distribution	6,336.9	6,070.6
Other Property, Plant and Equipment	1,038.7	992.9
Construction Work in Progress	491.6	365.0
Total Property, Plant and Equipment	10,937.6	10,421.3
Accumulated Depreciation and Amortization	2,541.6	2,458.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,396.0	7,963.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	270.8	293.0
Operating Lease Assets	74.4	81.2
Deferred Charges and Other Noncurrent Assets	334.4	601.1
TOTAL OTHER NONCURRENT ASSETS	679.6	975.3
TOTAL ASSETS	$ 9,425.1	$ 9,265.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2022 and December 31, 2021
(Unaudited)

	September 30, 2022	December 31, 2021
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 68.8	$ —
Accounts Payable:		
General	314.9	213.5
Affiliated Companies	126.6	125.4
Long-term Debt Due Within One Year – Nonaffiliated	0.1	0.1
Risk Management Liabilities	—	6.7
Customer Deposits	103.8	66.4
Accrued Taxes	367.0	702.4
Obligations Under Operating Leases	13.5	13.1
Other Current Liabilities	159.5	118.1
TOTAL CURRENT LIABILITIES	1,154.2	1,245.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,969.8	2,968.4
Long-term Risk Management Liabilities	45.1	85.8
Deferred Income Taxes	1,053.2	1,000.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,049.3	1,020.9
Obligations Under Operating Leases	60.6	68.6
Deferred Credits and Other Noncurrent Liabilities	60.7	29.2
TOTAL NONCURRENT LIABILITIES	5,238.7	5,173.8
TOTAL LIABILITIES	6,392.9	6,419.5
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock –No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	839.8	838.8
Retained Earnings	1,871.2	1,686.3
TOTAL COMMON SHAREHOLDER'S EQUITY	3,032.2	2,846.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 9,425.1	$ 9,265.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2022	2021
OPERATING ACTIVITIES		
Net Income	$ 229.9	$ 198.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	216.9	228.6
Deferred Income Taxes	29.3	29.3
Allowance for Equity Funds Used During Construction	(10.3)	(7.6)
Mark-to-Market of Risk Management Contracts	(49.6)	(19.9)
Property Taxes	264.7	234.9
Change in Other Noncurrent Assets	(19.7)	(1.1)
Change in Other Noncurrent Liabilities	82.5	4.6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(27.0)	20.7
Materials and Supplies	(11.6)	(0.6)
Accounts Payable	87.6	(19.1)
Customer Deposits	37.4	68.4
Accrued Taxes, Net	(344.5)	(289.7)
Other Current Assets	11.3	(7.8)
Other Current Liabilities	25.7	5.8
Net Cash Flows from Operating Activities	522.6	445.1
INVESTING ACTIVITIES		
Construction Expenditures	(600.6)	(536.6)
Change in Advances to Affiliates, Net	42.0	(622.9)
Other Investing Activities	21.3	10.7
Net Cash Flows Used for Investing Activities	(537.3)	(1,148.8)
FINANCING ACTIVITIES		
Capital Contribution from Parent	1.0	—
Issuance of Long-term Debt – Nonaffiliated	—	1,037.5
Change in Advances from Affiliates, Net	68.8	(259.2)
Retirement of Long-term Debt – Nonaffiliated	(0.1)	(0.1)
Principal Payments for Finance Lease Obligations	(3.6)	(3.7)
Dividends Paid on Common Stock	(45.0)	(71.9)
Other Financing Activities	0.8	0.5
Net Cash Flows from Financing Activities	21.9	703.1
Net Increase (Decrease) in Cash and Cash Equivalents	7.2	(0.6)
Cash and Cash Equivalents at Beginning of Period	3.0	7.4
Cash and Cash Equivalents at End of Period	$ 10.2	$ 6.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 75.8	$ 78.6
Net Cash Paid for Income Taxes	24.2	0.3
Noncash Acquisitions Under Finance Leases	2.1	1.4
Construction Expenditures Included in Current Liabilities as of September 30,	108.3	66.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	**2021**	**2022**	**2021**
	(in millions of KWhs)			
Retail:				
Residential	2,293	2,179	5,320	5,068
Commercial	1,547	1,476	3,976	3,781
Industrial	1,616	1,566	4,567	4,383
Miscellaneous	377	355	993	935
Total Retail	5,833	5,576	14,856	14,167
Wholesale	55	162	660	350
Total KWhs	5,888	5,738	15,516	14,517

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	**2021**	**2022**	**2021**
	(in degree days)			
Actual – Heating (a)	—	—	1,153	1,195
Normal – Heating (b)	—	1	1,085	1,078
Actual – Cooling (c)	1,678	1,491	2,475	2,075
Normal – Cooling (b)	1,407	1,404	2,074	2,079

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

Third Quarter of 2022 Compared to Third Quarter of 2021

Public Service Company of Oklahoma
Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Net Income
(in millions)

Third Quarter of 2021	$	93.2
Changes in Gross Margin:		
Retail Margins (a)		26.3
Transmission Revenues		0.5
Other Revenues		(0.1)
Total Change in Gross Margin		26.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(24.1)
Depreciation and Amortization		(10.6)
Taxes Other Than Income Taxes		(3.5)
Other Income		1.2
Non-Service Cost Components of Net Periodic Benefit Cost		1.0
Interest Expense		(6.2)
Total Change in Expenses and Other		(42.2)
Income Tax Benefit		29.2
Third Quarter of 2022	$	106.9

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

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

- **Retail Margins** increased $26 million primarily due to the following:
  - A $47 million increase due to a $26 million increase in base rate revenues and a $21 million increase in rider revenues. These increases were partially offset in other expense items below.
  - An $11 million increase in weather-related usage primarily due to a 13% increase in cooling degree days.

  These increases were partially offset by:
  - A $33 million decrease resulting from the NCWF PTC benefits provided to customers through fuel clause mechanisms.This decrease was partially offset in Income Tax Benefit below.

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

- **Other Operation and Maintenance** expenses increased $24 million primarily due to the following:
  - An $8 million increase in distribution expenses primarily due to an increase in overhead line maintenance.
  - A $7 million increase in transmission expenses primarily due to the following:
    - A $36 million increase related to a change in rider recovery, increased transmission investment and increased load.
    - A $4 million increase in transmission formula rate true-up activity. This increase was partially offset in Retail Margins above.

These increases were partially offset by:

- A $33 million decrease in recoverable SPP transmission expenses. This decrease was offset in Retail Margins above.

- A $3 million increase primarily due to an increase in maintenance expenses at the NCWF.
- A $3 million increase due to pre-construction costs associated with various renewable projects.

- **Depreciation and Amortization** increased $11 million primarily due to a higher depreciable base, implementation of new rates and the timing of refunds to customers under rate rider mechanisms.
- **Taxes Other Than Income Taxes** increased $4 million primarily due to a new infrastructure fee implemented by the City of Tulsa in March 2022 and increased property taxes. This increase was partially offset in Retail Margins above.
- **Interest Expense** increased $6 million primarily due to higher long-term debt balances.
- **Income Tax Benefit** increased $29 million primarily due to an increase in PTCs. This increase was partially offset in Retail Margins above.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Public Service Company of Oklahoma
Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Net Income
(in millions)

Nine Months Ended September 30, 2021	$	136.6
Changes in Gross Margin:		
Retail Margins (a)		82.0
Transmission Revenues		(1.1)
Total Change in Gross Margin		80.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(58.2)
Depreciation and Amortization		(23.7)
Taxes Other Than Income Taxes		(6.5)
Other Income		4.0
Non-Service Cost Components of Net Periodic Benefit Cost		3.0
Interest Expense		(17.9)
Total Change in Expenses and Other		(99.3)
Income Tax Benefit		37.5
Nine Months Ended September 30, 2022	$	155.7

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

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

- **Retail Margins** increased $82 million primarily due to the following:
  - A $95 million increase due to a $51 million increase in base rate revenues and a $44 million increase in rider revenues. These increases were partially offset in other expense items below.
  - A $21 million increase in weather-related usage primarily due to a 19% increase in cooling degree days.
  - A $12 million increase in weather-normalized margins primarily in the commercial and industrial classes.

  These increases were partially offset by:
  - A $46 million decrease resulting from the NCWF PTC benefits provided to customers through fuel clause mechanisms.This decrease was partially offset in Income Tax Benefit below.

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

- **Other Operation and Maintenance** expenses increased $58 million primarily due to the following:
  - An $18 million increase in transmission expenses primarily due to the following:
    - A $79 million increase due to a change in rider recovery, increased transmission investment and increased load.

    This increase was partially offset by:
    - A $58 million decrease in recoverable SPP transmission expenses. This decrease was offset in Retail Margins above.
    - A $3 million decrease in transmission formula rate true-up activity. This decrease was partially offset in Retail Margins above.
  - A $16 million increase in distribution expenses primarily due to an increase in overhead line maintenance.
  - A $15 million increase in generating expenses primarily due to an increase in maintenance expenses at the NCWF and Northeastern.

- **Depreciation and Amortization** expenses increased $24 million primarily due to a higher depreciable base, implementation of new rates and the timing of refunds to customers under rate rider mechanisms.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to a new infrastructure fee implemented by the City of Tulsa in March 2022 and increased property taxes. This increase was partially offset in Retail Margins above.
- **Other Income** increased $4 million primarily related to carrying charges on regulatory assets resulting from the February 2021 severe winter weather event.
- **Interest Expense** increased $18 million due to higher long-term debt balances.
- **Income Tax Benefit** increased $38 million primarily due to an increase in PTCs. This increase was partially offset in Retail Margins above.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
REVENUES				
Electric Generation, Transmission and Distribution	$ 606.5	$ 481.3	$ 1,432.9	$ 1,117.4
Sales to AEP Affiliates	0.7	1.0	2.1	3.1
Other Revenues	1.0	1.5	3.7	3.9
TOTAL REVENUES	608.2	483.8	1,438.7	1,124.4
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	293.6	195.9	674.2	440.8
Other Operation	116.3	102.3	301.0	262.7
Maintenance	31.3	21.2	88.0	68.1
Depreciation and Amortization	59.5	48.9	172.7	149.0
Taxes Other Than Income Taxes	15.6	12.1	43.6	37.1
TOTAL EXPENSES	516.3	380.4	1,279.5	957.7
OPERATING INCOME	91.9	103.4	159.2	166.7
Other Income (Expense):				
Other Income	3.0	1.8	8.5	4.5
Non-Service Cost Components of Net Periodic Benefit Cost	3.1	2.1	9.4	6.4
Interest Expense	(22.4)	(16.2)	(62.6)	(44.7)
INCOME BEFORE INCOME TAX BENEFIT	75.6	91.1	114.5	132.9
Income Tax Benefit	(31.3)	(2.1)	(41.2)	(3.7)
NET INCOME	$ 106.9	$ 93.2	$ 155.7	$ 136.6

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	**2021**	**2022**	**2021**
Net Income	$ 106.9	$ 93.2	$ 155.7	$ 136.6
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2022 and 2021, Respectively, and $0 and $0 for the Nine Months Ended September 30, 2022 and 2021, Respectively	—	—	—	(0.1)
TOTAL COMPREHENSIVE INCOME	$ 106.9	$ 93.2	$ 155.7	$ 136.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 157.2	$ 414.0	$ 974.3	$ 0.1	$ 1,545.6
apital Contribution from Parent		425.0			425.0
et Loss			(2.7)		(2.7)
her Comprehensive Loss				(0.1)	(0.1)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2021	157.2	839.0	971.6	—	1,967.8
apital Contribution from Parent		200.0			200.0
mmon Stock Dividends			(10.0)		(10.0)
et Income			46.1		46.1
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2021	157.2	1,039.0	1,007.7	—	2,203.9
mmon Stock Dividends			(10.0)		(10.0)
et Income			93.2		93.2
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2021	$ 157.2	$ 1,039.0	$ 1,090.9	$ —	$ 2,287.1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2021	$ 157.2	$ 1,039.0	$ 1,095.4	$ —	$ 2,291.6
et Income			5.8		5.8
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2022	157.2	1,039.0	1,101.2	—	2,297.4
apital Contribution from Parent		2.2			2.2
et Income			43.0		43.0
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2022	157.2	1,041.2	1,144.2	—	2,342.6
apital Contribution from Parent		1.1			1.1
mmon Stock Dividends			(20.0)		(20.0)
et Income			106.9		106.9
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2022	$ 157.2	$ 1,042.3	$ 1,231.1	$ —	$ 2,430.6

e Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 5.5	$ 1.3
Accounts Receivable:		
Customers	44.2	41.5
Affiliated Companies	93.5	35.0
Miscellaneous	5.7	0.6
Total Accounts Receivable	143.4	77.1
Fuel	8.4	14.5
Materials and Supplies	89.0	56.2
Risk Management Assets	44.5	12.1
Accrued Tax Benefits	66.4	17.6
Regulatory Asset for Under-Recovered Fuel Costs	178.7	194.6
Prepayments and Other Current Assets	32.8	13.4
TOTAL CURRENT ASSETS	568.7	386.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	2,386.0	1,802.4
Transmission	1,131.2	1,107.7
Distribution	3,137.3	3,004.9
Other Property, Plant and Equipment	464.8	437.0
Construction Work in Progress	225.4	156.0
Total Property, Plant and Equipment	7,344.7	6,508.0
Accumulated Depreciation and Amortization	1,810.5	1,705.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,534.2	4,802.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	606.2	1,037.4
Employee Benefits and Pension Assets	97.7	95.2
Operating Lease Assets	107.3	68.9
Deferred Charges and Other Noncurrent Assets	23.0	7.9
TOTAL OTHER NONCURRENT ASSETS	834.2	1,209.4
TOTAL ASSETS	$ 6,937.1	$ 6,399.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2022 and December 31, 2021
(Unaudited)

	September 30, 2022	December 31, 2021
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 223.5	$ 72.3
Accounts Payable:		
General	249.0	157.4
Affiliated Companies	105.0	51.0
Long-term Debt Due Within One Year – Nonaffiliated	0.5	125.5
Risk Management Liabilities	—	3.7
Customer Deposits	60.5	56.2
Accrued Taxes	54.9	27.0
Obligations Under Operating Leases	8.4	6.9
Other Current Liabilities	75.0	62.7
TOTAL CURRENT LIABILITIES	776.8	562.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,913.1	1,788.0
Deferred Income Taxes	794.9	782.3
Regulatory Liabilities and Deferred Investment Tax Credits	827.9	835.3
Asset Retirement Obligations	74.6	57.5
Obligations Under Operating Leases	100.3	62.2
Deferred Credits and Other Noncurrent Liabilities	18.9	19.4
TOTAL NONCURRENT LIABILITIES	3,729.7	3,544.7
TOTAL LIABILITIES	4,506.5	4,107.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157.2	157.2
Paid-in Capital	1,042.3	1,039.0
Retained Earnings	1,231.1	1,095.4
TOTAL COMMON SHAREHOLDER'S EQUITY	2,430.6	2,291.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 6,937.1	$ 6,399.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
OPERATING ACTIVITIES		
Net Income	$ 155.7	$ 136.6
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	172.7	149.0
Deferred Income Taxes	(20.0)	109.8
Mark-to-Market of Risk Management Contracts	(36.1)	(8.2)
Property Taxes	(12.2)	(10.9)
Deferred Fuel Over/Under-Recovery, Net	454.0	(776.4)
Change in Other Noncurrent Assets	(18.1)	(14.3)
Change in Other Noncurrent Liabilities	15.8	4.5
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(66.3)	(13.4)
Fuel, Materials and Supplies	(25.8)	9.9
Accounts Payable	150.8	16.4
Accrued Taxes, Net	(20.9)	9.3
Other Current Assets	(19.2)	(5.9)
Other Current Liabilities	11.0	(18.4)
Net Cash Flows from (Used for) Operating Activities	741.4	(412.0)
INVESTING ACTIVITIES		
Construction Expenditures	(322.6)	(219.6)
Change in Advances to Affiliates, Net	—	(59.5)
Acquisition of the North Central Wind Energy Facilities	(549.3)	(297.0)
Other Investing Activities	2.9	1.9
Net Cash Flows Used for Investing Activities	(869.0)	(574.2)
FINANCING ACTIVITIES		
Capital Contribution from Parent	3.3	625.0
Issuance of Long-term Debt – Nonaffiliated	499.7	1,290.0
Change in Advances from Affiliates, Net	151.2	(155.4)
Retirement of Long-term Debt – Nonaffiliated	(500.4)	(750.4)
Principal Payments for Finance Lease Obligations	(2.4)	(2.5)
Dividends Paid on Common Stock	(20.0)	(20.0)
Other Financing Activities	0.4	0.5
Net Cash Flows from Financing Activities	131.8	987.2
Net Increase in Cash and Cash Equivalents	4.2	1.0
Cash and Cash Equivalents at Beginning of Period	1.3	2.6
Cash and Cash Equivalents at End of Period	$ 5.5	$ 3.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 63.1	$ 42.9
Net Cash Paid (Received) for Income Taxes	21.9	(101.2)
Noncash Acquisitions Under Finance Leases	1.7	3.1
Construction Expenditures Included in Current Liabilities as of September 30,	50.1	44.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions of KWhs)			
Retail:				
Residential	2,019	1,999	5,157	4,973
Commercial	1,631	1,616	4,385	4,221
Industrial	1,367	1,203	3,876	3,468
Miscellaneous	17	19	55	58
Total Retail	5,034	4,837	13,473	12,720
Wholesale	1,744	2,170	5,312	5,103
Total KWhs	6,778	7,007	18,785	17,823

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in degree days)			
Actual – Heating (a)	—	—	704	789
Normal – Heating (b)	—	1	726	723
Actual – Cooling (c)	1,627	1,478	2,642	2,251
Normal – Cooling (b)	1,420	1,416	2,195	2,195

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

Third Quarter of 2022 Compared to Third Quarter of 2021

Reconciliation of Third Quarter of 2021 to Third Quarter of 2022
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Third Quarter of 2021	$	108.9
Changes in Gross Margin:		
Retail Margins (a)		41.6
Margins from Off-system Sales		7.2
Transmission Revenues		7.7
Other Revenues		0.4
Total Change in Gross Margin		56.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(21.6)
Depreciation and Amortization		(21.0)
Taxes Other Than Income Taxes		(5.3)
Interest Income		(0.1)
Allowance for Equity Funds Used During Construction		(0.4)
Non-Service Cost Components of Net Periodic Benefit Cost		1.1
Interest Expense		(3.5)
Total Change in Expenses and Other		(50.8)
Income Tax Expense		24.1
Equity Earnings of Unconsolidated Subsidiary		(0.7)
Net Income Attributable to Noncontrolling Interest		1.0
Third Quarter of 2022	$	139.4

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

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

- **Retail Margins** increased $42 million primarily due to the following:
  - A $40 million increase primarily due to base rate revenue increases in Texas and Arkansas and rider increases in all retail jurisdictions. These increases were partially offset in other expense items below.
  - A $12 million increase in weather-related usage primarily due to a 10% increase in cooling degree days.
  - A $6 million increase in weather-normalized margins primarily due to the commercial and industrial classes.

  These increases were partially offset by:
  - A $14 million decrease resulting from the NCWF PTC benefits provided to customers through fuel clause mechanisms.This decrease was partially offset in Income Tax Benefit below.
- **Margins from Off-system Sales** increased $7 million due to an increase in Turk Plant merchant sales.
- **Transmission Revenues** increased $8 million primarily due to continued investment in transmission assets and increased load.

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

- **Other Operation and Maintenance** expenses increased $22 million primarily due to the following:
  - A $7 million increase in transmission expenses primarily due to the following:
    - A $6 million increase in recoverable SPP transmission expenses. This increase was offset in Retail Margins above.
    - A $2 million increase in transmission formula rate true-up activity.
  - A $4 million increase in distribution expenses primarily due to vegetation management expenses.
  - A $3 million increase related to the assumption of additional Sabine reclamation costs from a joint owner.
  - A $2 million increase due to energy efficiency programs. This increase was offset in Retail Margins above.
  - A $2 million increase in administrative and general expenses primarily due to rate case expenses and regulatory fees.
- **Depreciation and Amortization** expenses increased $21 million primarily due to the implementation of new rates in Arkansas and Texas, a higher depreciable base and the NCWF rider. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $5 million primarily due to increased property taxes.
- **Interest Expense** increased $4 million primarily due to an increase in long-term debt balances and Advances from Affiliates.
- **Income Tax Expense** decreased $24 million primarily due to an increase in PTCs. This decrease was partially offset in Retail Margins above.

Nine Months Ended September 30, 2022 Compared to Nine Months Ended September 30, 2021

Reconciliation of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2022
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Nine Months Ended September 30, 2021	$	208.1
Changes in Gross Margin:		
Retail Margins (a)		93.5
Margins from Off-system Sales		(10.3)
Transmission Revenues		18.6
Other Revenues		0.4
Total Change in Gross Margin		102.2
Changes in Expenses and Other:		
Other Operation and Maintenance		(46.4)
Depreciation and Amortization		(34.4)
Taxes Other Than Income Taxes		(5.9)
Interest Income		7.0
Allowance for Equity Funds Used During Construction		(2.0)
Non-Service Cost Components of Net Periodic Benefit Cost		3.2
Interest Expense		(9.6)
Total Change in Expenses and Other		(88.1)
Income Tax Expense		40.0
Equity Earnings of Unconsolidated Subsidiary		(1.5)
Net Income Attributable to Noncontrolling Interest		(0.5)
Nine Months Ended September 30, 2022	$	260.2

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

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

- **Retail Margins** increased $94 million primarily due to the following:
  - An $80 million increase primarily due to base rate revenue increases in Texas and Arkansas and rider increases in all retail jurisdictions. These increases were partially offset in other expense items below.
  - A $27 million increase in weather-related usage primarily due to a 17% increase in cooling degree days, partially offset by an 11% decrease in heating degree days.
  - An $11 million increase in weather-normalized margins primarily due to the commercial and residential classes, partially offset by the industrial class.

  These increases were partially offset by:
  - A $16 million decrease resulting from the NCWF PTC benefits provided to customers through fuel clause mechanisms.This decrease was partially offset in Income Tax Benefit below.
  - An $8 million decrease in municipal and cooperative revenues primarily due to the February 2021 severe winter weather event.
- **Margins from Off-system Sales** decreased $10 million primarily due to Turk Plant merchant sales as a result of the February 2021 severe winter weather event.

- **Transmission Revenues** increased $19 million primarily due to the following:
  - A $21 million increase due to continued investment in transmission assets and increased load.

  This increase was partially offset by:
  - A $3 million decrease due to formula rate true-up activity.

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

- **Other Operation and Maintenance** expenses increased $46 million primarily due to the following:
  - A $12 million increase in transmission expenses primarily due to the following:
    - A $6 million increase in recoverable SPP transmission expenses. This increase was offset in Retail Margins above.
    - A $4 million increase due to increased transmission investment and load.
    - A $3 million increase in transmission vegetation management expenses.

    These increases were partially offset by:
    - A $4 million decrease in formula rate true-up activity.
  - A $6 million increase due to pre-construction costs associated with various renewable projects.
  - A $6 million increase in generation related expenses.
  - A $5 million increase in administrative and general expenses primarily due to regulatory fees and employee-related expenses.
  - A $5 million increase in distribution expenses primarily due to vegetation management expenses.
  - A $5 million increase due to energy efficiency programs. This increase was offset in Retail Margins above.
  - A $3 million increase related to the assumption of additional Sabine reclamation costs from a joint owner.
- **Depreciation and Amortization** expenses increased $34 million primarily due to the implementation of new rates in Arkansas and Texas, a higher depreciable base and the NCWF rider. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to increased property taxes.
- **Interest Income** increased $7 million primarily related to carrying charges on regulatory assets resulting from the February 2021 severe winter weather event.
- **Interest Expense** increased $10 million primarily due to an increase in long-term debt balances and Advances from Affiliates.
- **Income Tax Expense** decreased $40 million primarily due to an increase in PTCs, partially offset by an increase in pretax book income and an increase in state tax expense. The decrease in Income Tax Expense driven by the increase in PTCs is partially offset in Retail Margins above.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
REVENUES				
Electric Generation, Transmission and Distribution	$ 698.8	$ 570.1	$ 1,703.7	$ 1,596.6
Sales to AEP Affiliates	18.2	13.5	43.7	32.2
Other Revenues	0.5	0.5	1.5	1.5
TOTAL REVENUES	717.5	584.1	1,748.9	1,630.3
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	290.9	214.4	669.1	652.7
Other Operation	114.1	91.7	308.7	270.6
Maintenance	32.9	33.7	107.8	99.5
Depreciation and Amortization	95.8	74.8	251.8	217.4
Taxes Other Than Income Taxes	34.2	28.9	94.9	89.0
TOTAL EXPENSES	567.9	443.5	1,432.3	1,329.2
OPERATING INCOME	149.6	140.6	316.6	301.1
Other Income (Expense):				
Interest Income	2.7	2.8	13.9	6.9
Allowance for Equity Funds Used During Construction	1.0	1.4	3.4	5.4
Non-Service Cost Components of Net Periodic Benefit Cost	3.2	2.1	9.4	6.2
Interest Expense	(35.2)	(31.7)	(102.0)	(92.4)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	121.3	115.2	241.3	227.2
Income Tax Expense (Benefit)	(17.8)	6.3	(21.0)	19.0
Equity Earnings of Unconsolidated Subsidiary	0.3	1.0	1.0	2.5
NET INCOME	139.4	109.9	263.3	210.7
Net Income Attributable to Noncontrolling Interest	—	1.0	3.1	2.6
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 139.4	$ 108.9	$ 260.2	$ 208.1

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Net Income	$ 139.4	$ 109.9	$ 263.3	$ 210.7
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0.1 for the Three Months Ended September 30, 2022 and 2021, Respectively, and $0 and $0.3 for the Nine Months Ended September 30, 2022 and 2021, Respectively	—	0.3	—	1.1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2022 and 2021, Respectively, and $(0.3) and $(0.3) for the Nine Months Ended September 30, 2022 and 2021, Respectively	(0.4)	(0.4)	(1.2)	(1.2)
TOTAL OTHER COMPREHENSIVE LOSS	(0.4)	(0.1)	(1.2)	(0.1)
TOTAL COMPREHENSIVE INCOME	139.0	109.8	262.1	210.6
Total Comprehensive Income Attributable to Noncontrolling Interest	—	1.0	3.1	2.6
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 139.0	$ 108.8	$ 259.0	$ 208.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2020	$ 0.1	$ 812.2	$ 1,811.9	$ 1.9	$ 1.6	$ 2,627.7
Capital Contribution from Parent		100.0				100.0
Common Stock Dividends – Nonaffiliated					(1.0)	(1.0)
Net Income			62.4		1.0	63.4
TOTAL EQUITY – MARCH 31, 2021	0.1	912.2	1,874.3	1.9	1.6	2,790.1
Capital Contribution from Parent		75.0				75.0
Common Stock Dividends – Nonaffiliated					(0.6)	(0.6)
Net Income			36.8		0.6	37.4
TOTAL EQUITY – JUNE 30, 2021	0.1	987.2	1,911.1	1.9	1.6	2,901.9
Capital Contribution from Parent		105.0				105.0
Common Stock Dividends – Nonaffiliated					(2.2)	(2.2)
Net Income			108.9		1.0	109.9
Other Comprehensive Loss				(0.1)		(0.1)
TOTAL EQUITY – SEPTEMBER 30, 2021	$ 0.1	$ 1,092.2	$ 2,020.0	$ 1.8	$ 0.4	$ 3,114.5
TOTAL EQUITY – DECEMBER 31, 2021	$ 0.1	$ 1,092.2	$ 2,050.9	$ 6.7	$ (0.1)	$ 3,149.8
Capital Contribution from Parent		350.0				350.0
Common Stock Dividends – Nonaffiliated					(0.8)	(0.8)
Net Income			44.1		1.0	45.1
Other Comprehensive Loss				(0.3)		(0.3)
TOTAL EQUITY – MARCH 31, 2022	0.1	1,442.2	2,095.0	6.4	0.1	3,543.8
Capital Contribution from Parent		2.2				2.2
Common Stock Dividends			(12.5)			(12.5)
Common Stock Dividends – Nonaffiliated					(0.7)	(0.7)
Net Income			76.7		2.1	78.8
Other Comprehensive Loss				(0.5)		(0.5)
TOTAL EQUITY – JUNE 30, 2022	0.1	1,444.4	2,159.2	5.9	1.5	3,611.1
Capital Contribution from Parent		1.1				1.1
Common Stock Dividends			(45.0)			(45.0)
Common Stock Dividends – Nonaffiliated					(1.1)	(1.1)
Net Income			139.4		—	139.4
Other Comprehensive Loss				(0.4)		(0.4)
TOTAL EQUITY – SEPTEMBER 30, 2022	$ 0.1	$ 1,445.5	$ 2,253.6	$ 5.5	$ 0.4	$ 3,705.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2022 and December 31, 2021
(in millions)
(Unaudited)

	September 30, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents (September 30, 2022 and December 31, 2021 Amounts Include $79.2 and $49.9, Respectively, Related to Sabine)	$ 84.4	$ 51.2
Advances to Affiliates	2.1	155.9
Accounts Receivable:		
Customers	31.9	35.8
Affiliated Companies	53.8	38.3
Miscellaneous	18.6	12.3
Total Accounts Receivable	104.3	86.4
Fuel (September 30, 2022 and December 31, 2021 Amounts Include $9.9 and $13.1, Respectively, Related to Sabine)	55.3	82.2
Materials and Supplies (September 30, 2022 and December 31, 2021 Amounts Include $7.2 and $12, Respectively, Related to Sabine)	85.3	81.9
Risk Management Assets	36.4	9.8
Accrued Tax Benefits	88.4	17.8
Regulatory Asset for Under-Recovered Fuel Costs	333.8	143.9
Prepayments and Other Current Assets	50.0	39.4
TOTAL CURRENT ASSETS	840.0	668.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,454.6	4,734.5
Transmission	2,380.3	2,316.9
Distribution	2,622.5	2,514.3
Other Property, Plant and Equipment (September 30, 2022 and December 31, 2021 Amounts Include $219.9 and $219.9, Respectively, Related to Sabine)	801.4	764.0
Construction Work in Progress	345.3	240.7
Total Property, Plant and Equipment	11,604.1	10,570.4
Accumulated Depreciation and Amortization (September 30, 2022 and December 31, 2021 Amounts Include $201.8 and $168.1, Respectively, Related to Sabine)	3,444.2	3,170.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,159.9	7,400.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	992.4	1,005.3
Deferred Charges and Other Noncurrent Assets	300.8	251.8
TOTAL OTHER NONCURRENT ASSETS	1,293.2	1,257.1
TOTAL ASSETS	$ 10,293.1	$ 9,325.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2022 and December 31, 2021
(Unaudited)

	September 30, 2022	December 31, 2021
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 156.3	$ —
Accounts Payable:		
General	206.2	163.6
Affiliated Companies	100.5	61.4
Long-term Debt Due Within One Year – Nonaffiliated	6.2	6.2
Risk Management Liabilities	—	2.1
Customer Deposits	65.3	62.4
Accrued Taxes	113.8	44.3
Accrued Interest	30.3	36.0
Obligations Under Operating Leases	8.4	8.1
Other Current Liabilities	129.0	154.6
TOTAL CURRENT LIABILITIES	816.0	538.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,386.2	3,389.0
Deferred Income Taxes	1,112.0	1,087.6
Regulatory Liabilities and Deferred Investment Tax Credits	818.2	806.9
Asset Retirement Obligations	247.5	192.7
Employee Benefits and Pension Obligations	23.2	20.3
Obligations Under Operating Leases	122.5	77.7
Deferred Credits and Other Noncurrent Liabilities	62.4	63.0
TOTAL NONCURRENT LIABILITIES	5,772.0	5,637.2
TOTAL LIABILITIES	6,588.0	6,175.9
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 3,680 Shares		
Outstanding – 3,680 Shares	0.1	0.1
Paid-in Capital	1,445.5	1,092.2
Retained Earnings	2,253.6	2,050.9
Accumulated Other Comprehensive Income (Loss)	5.5	6.7
TOTAL COMMON SHAREHOLDER'S EQUITY	3,704.7	3,149.9
Noncontrolling Interest	0.4	(0.1)
TOTAL EQUITY	3,705.1	3,149.8
TOTAL LIABILITIES AND EQUITY	$ 10,293.1	$ 9,325.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2022 and 2021
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2022	2021
OPERATING ACTIVITIES		
Net Income	$ 263.3	$ 210.7
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	251.8	217.4
Deferred Income Taxes	7.5	22.5
Allowance for Equity Funds Used During Construction	(3.4)	(5.4)
Mark-to-Market of Risk Management Contracts	(27.6)	(18.1)
Property Taxes	(22.0)	(20.0)
Deferred Fuel Over/Under-Recovery, Net	(82.0)	(506.8)
Change in Regulatory Assets	3.1	(91.5)
Change in Other Noncurrent Assets	52.0	38.3
Change in Other Noncurrent Liabilities	17.3	40.0
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(17.9)	(70.2)
Fuel, Materials and Supplies	23.5	115.1
Accounts Payable	78.9	(21.1)
Accrued Taxes, Net	(1.1)	72.2
Other Current Assets	(12.0)	4.2
Other Current Liabilities	(38.1)	(48.2)
Net Cash Flows from (Used for) Operating Activities	493.3	(60.9)
INVESTING ACTIVITIES		
Construction Expenditures	(397.0)	(277.2)
Change in Advances to Affiliates, Net	153.8	—
Acquisition of the North Central Wind Energy Facilities	(658.0)	(355.8)
Other Investing Activities	3.9	2.1
Net Cash Flows Used for Investing Activities	(897.3)	(630.9)
FINANCING ACTIVITIES		
Capital Contribution from Parent	353.3	280.0
Issuance of Long-term Debt – Nonaffiliated	—	496.4
Change in Short-term Debt – Nonaffiliated	—	(35.0)
Change in Advances from Affiliates, Net	156.3	(1.7)
Retirement of Long-term Debt – Nonaffiliated	(4.7)	(4.7)
Principal Payments for Finance Lease Obligations	(8.0)	(8.1)
Dividends Paid on Common Stock	(57.5)	—
Dividends Paid on Common Stock – Nonaffiliated	(2.6)	(3.8)
Other Financing Activities	0.4	0.5
Net Cash Flows from Financing Activities	437.2	723.6
Net Increase in Cash and Cash Equivalents	33.2	31.8
Cash and Cash Equivalents at Beginning of Period	51.2	13.2
Cash and Cash Equivalents at End of Period	$ 84.4	$ 45.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 102.1	$ 98.0
Net Cash Paid (Received) for Income Taxes	34.7	(11.3)
Noncash Acquisitions Under Finance Leases	3.2	4.4
Construction Expenditures Included in Current Liabilities as of September 30,	71.8	46.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 144.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

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

1. SIGNIFICANT ACCOUNTING MATTERS

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

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three and nine months ended September 30, 2022 is not necessarily indicative of results that may be expected for the year ending December 31, 2022. The condensed financial statements are unaudited and should be read in conjunction with the audited 2021 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 24, 2022.

AEP System Tax Allocation

The Registrant Subsidiaries join in the filing of a consolidated tax return. Historically, the allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocated the benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the AEP System subsidiaries through a reduction of current tax expense. In the first quarter of 2022, AEP and subsidiaries changed accounting for the Parent Company Loss Benefit from a reduction of current tax expense to an allocation through equity. The impact of this change was immaterial to the Registrant Subsidiaries' financial statements.

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

The cost of purchased electricity, fuel and related emission allowances and emission control chemicals/consumables is charged to Purchased Electricity, 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 an expectation that refunds or recoveries will extend beyond a one year period, based on a company's filing with a commission or a commission directive. 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.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Three Months Ended September 30,			
	2022		2021	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 683.7		$ 796.0	
Weighted-Average Number of Basic AEP Common Shares Outstanding	513.7	$ 1.33	501.2	$ 1.59
Weighted-Average Dilutive Effect of Stock-Based Awards	1.6	—	1.4	(0.01)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	515.3	$ 1.33	502.6	$ 1.58

	Nine Months Ended September 30,			
	2022		2021	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,922.9		$ 1,949.2	
Weighted-Average Number of Basic AEP Common Shares Outstanding	511.2	$ 3.76	499.4	$ 3.90
Weighted-Average Dilutive Effect of Stock-Based Awards	1.5	(0.01)	1.2	(0.01)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	512.7	$ 3.75	500.6	$ 3.89

Equity Units are potentially dilutive securities and were excluded from the calculation of diluted EPS for the three and nine months ended September 30, 2022 and 2021, as the dilutive stock price threshold was not met. See Note 12 - Financing Activities for more information related to Equity Units.

There were 0 and 377 thousand antidilutive shares outstanding as of September 30, 2022 and 2021, respectively.

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 statements of cash flows:

	September 30, 2022		
	AEP	AEP Texas	APCo
		(in millions)	
Cash and Cash Equivalents	$ 522.2	$ 0.1	$ 6.7
Restricted Cash	55.1	47.7	7.4
Total Cash, Cash Equivalents and Restricted Cash	$ 577.3	$ 47.8	$ 14.1

	December 31, 2021		
	AEP	AEP Texas	APCo
		(in millions)	
Cash and Cash Equivalents	$ 403.4	$ 0.1	$ 2.5
Restricted Cash	48.0	30.4	17.6
Total Cash, Cash Equivalents and Restricted Cash	$ 451.4	$ 30.5	$ 20.1

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Nine Months Ended September 30, 2022	2021
	(in millions)	
Cash Paid for:		
Interest, Net of Capitalized Amounts	$ 856.8	$ 775.2
Income Taxes	104.1	9.3
Noncash Investing and Financing Activities:		
Acquisitions Under Finance Leases	22.3	23.0
Construction Expenditures Included in Current Liabilities as of September 30,	985.8	764.1
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	8.5	0.3
Noncash Contribution of Assets to Cedar Creek Project	—	(9.3)
Noncontrolling Interest Assumed - Dry Lake Solar Project	—	35.0

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. There are no new standards expected to have a material impact on the Registrants' financial statements.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants except AEPTCo and OPCo.

Presentation of Comprehensive Income

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

AEP

	Cash Flow Hedges		Pension	
Three Months Ended September 30, 2022	**Commodity**	**Interest Rate**	**and OPEB**	**Total**
		(in millions)		
Balance in AOCI as of June 30, 2022	$ 533.6	$ (10.8)	$ 28.6	$ 551.4
Change in Fair Value Recognized in AOCI	94.3	7.4 (a)	—	101.7
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	0.2	—	—	0.2
Purchased Electricity for Resale (b)	(222.6)	—	—	(222.6)
Interest Expense (b)	—	0.9	—	0.9
Amortization of Prior Service Cost (Credit)	—	—	(6.2)	(6.2)
Amortization of Actuarial (Gains) Losses	—	—	2.2	2.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(222.4)	0.9	(4.0)	(225.5)
Income Tax (Expense) Benefit	(46.6)	0.1	(0.8)	(47.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(175.8)	0.8	(3.2)	(178.2)
Net Current Period Other Comprehensive Income (Loss)	(81.5)	8.2	(3.2)	(76.5)
Balance in AOCI as of September 30, 2022	$ 452.1	$ (2.6)	$ 25.4	$ 474.9

	Cash Flow Hedges		Pension	
Three Months Ended September 30, 2021	**Commodity**	**Interest Rate**	**and OPEB**	**Total**
		(in millions)		
Balance in AOCI as of June 30, 2021	$ 110.3	$ (32.2)	$ 18.9	$ 97.0
Change in Fair Value Recognized in AOCI	220.8	4.9 (a)	—	225.7
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity for Resale (b)	(59.7)	—	—	(59.7)
Interest Expense (b)	—	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	(4.8)	(4.8)
Amortization of Actuarial (Gains) Losses	—	—	2.3	2.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(59.7)	1.5	(2.5)	(60.7)
Income Tax (Expense) Benefit	(12.5)	0.3	(0.5)	(12.7)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(47.2)	1.2	(2.0)	(48.0)
Net Current Period Other Comprehensive Income (Loss)	173.6	6.1	(2.0)	177.7
Balance in AOCI as of September 30, 2021	$ 283.9	$ (26.1)	$ 16.9	$ 274.7

AEP

Nine Months Ended September 30, 2022	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of December 31, 2021	$ 163.7	$ (21.3)	$ 42.4	$ 184.8
Change in Fair Value Recognized in AOCI	629.8	16.2 (a)	—	646.0
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	0.2	—	—	0.2
Purchased Electricity for Resale (b)	(432.3)	—	—	(432.3)
Interest Expense (b)	—	3.1	—	3.1
Amortization of Prior Service Cost (Credit)	—	—	(16.5)	(16.5)
Amortization of Actuarial (Gains) Losses	—	—	6.4	6.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(432.1)	3.1	(10.1)	(439.1)
Income Tax (Expense) Benefit	(90.7)	0.6	(2.1)	(92.2)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(341.4)	2.5	(8.0)	(346.9)
Reclassifications of KPCo Pension and OPEB Regulatory Assets to AOCI	—	—	(11.4)	(11.4)
Income Tax (Expense) Benefit	—	—	(2.4)	(2.4)
Reclassifications of KPCo Pension and OPEB Regulatory Assets to AOCI, Net of Income Tax (Expense) Benefit	—	—	(9.0)	(9.0)
Net Current Period Other Comprehensive Income (Loss)	288.4	18.7	(17.0)	290.1
Balance in AOCI as of September 30, 2022	$ 452.1	$ (2.6)	$ 25.4	$ 474.9

Nine Months Ended September 30, 2021	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of December 31, 2020	$ (60.6)	$ (47.5)	$ 23.0	$ (85.1)
Change in Fair Value Recognized in AOCI	534.5	17.6 (a)	—	552.1
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (b)	0.7	—	—	0.7
Purchased Electricity for Resale (b)	(241.2)	—	—	(241.2)
Interest Expense (b)	—	4.8	—	4.8
Amortization of Prior Service Cost (Credit)	—	—	(14.5)	(14.5)
Amortization of Actuarial (Gains) Losses	—	—	6.8	6.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(240.5)	4.8	(7.7)	(243.4)
Income Tax (Expense) Benefit	(50.5)	1.0	(1.6)	(51.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(190.0)	3.8	(6.1)	(192.3)
Net Current Period Other Comprehensive Income (Loss)	344.5	21.4	(6.1)	359.8
Balance in AOCI as of September 30, 2021	$ 283.9	$ (26.1)	$ 16.9	$ 274.7

AEP Texas

Three Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2022	$ (0.8)	$ (5.2)	$ (6.0)
Change in Fair Value Recognized in AOCI	0.1	—	0.1
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.3	—	0.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.3	—	0.3
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.2	—	0.2
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of September 30, 2022	$ (0.5)	$ (5.2)	$ (5.7)

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2021	$ (1.8)	$ (6.5)	$ (8.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.4	—	0.4
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	—	0.3
Net Current Period Other Comprehensive Income (Loss)	0.3	—	0.3
Balance in AOCI as of September 30, 2021	$ (1.5)	$ (6.5)	$ (8.0)

AEP Texas

Nine Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2021	$ (1.3)	$ (5.2)	$ (6.5)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.0	—	1.0
Income Tax (Expense) Benefit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.8	—	0.8
Net Current Period Other Comprehensive Income (Loss)	0.8	—	0.8
Balance in AOCI as of September 30, 2022	$ (0.5)	$ (5.2)	$ (5.7)

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (2.3)	$ (6.6)	$ (8.9)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.0	—	1.0
Amortization of Prior Service Cost (Credit)	—	(0.1)	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.0	0.1	1.1
Income Tax (Expense) Benefit	0.2	—	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.8	0.1	0.9
Net Current Period Other Comprehensive Income (Loss)	0.8	0.1	0.9
Balance in AOCI as of September 30, 2021	$ (1.5)	$ (6.5)	$ (8.0)

APCo

Three Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2022	$ 7.1	$ 14.8	$ 21.9
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.3)	—	(0.3)
Amortization of Prior Service Cost (Credit)	—	(1.4)	(1.4)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.3)	(1.4)	(1.7)
Income Tax (Expense) Benefit	(0.1)	(0.3)	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.2)	(1.1)	(1.3)
Net Current Period Other Comprehensive Income (Loss)	(0.2)	(1.1)	(1.3)
Balance in AOCI as of September 30, 2022	$ 6.9	$ 13.7	$ 20.6

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2021	$ 8.0	$ 5.9	$ 13.9
Change in Fair Value Recognized in AOCI	0.2	—	0.2
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.6)	—	(0.6)
Amortization of Prior Service Cost (Credit)	—	(1.2)	(1.2)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.6)	(1.2)	(1.8)
Income Tax (Expense) Benefit	(0.1)	(0.2)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.5)	(1.0)	(1.5)
Net Current Period Other Comprehensive Income (Loss)	(0.3)	(1.0)	(1.3)
Balance in AOCI as of September 30, 2021	$ 7.7	$ 4.9	$ 12.6

APCo

Nine Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2021	$ 7.5	$ 16.9	$ 24.4
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(0.8)	—	(0.8)
Amortization of Prior Service Cost (Credit)	—	(4.1)	(4.1)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.8)	(4.1)	(4.9)
Income Tax (Expense) Benefit	(0.2)	(0.9)	(1.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.6)	(3.2)	(3.8)
Net Current Period Other Comprehensive Income (Loss)	(0.6)	(3.2)	(3.8)
Balance in AOCI as of September 30, 2022	$ 6.9	$ 13.7	$ 20.6

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (0.8)	$ 8.0	$ 7.2
Change in Fair Value Recognized in AOCI	9.3	—	9.3
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	(1.0)	—	(1.0)
Amortization of Prior Service Cost (Credit)	—	(3.9)	(3.9)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.0)	(3.9)	(4.9)
Income Tax (Expense) Benefit	(0.2)	(0.8)	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)	(3.1)	(3.9)
Net Current Period Other Comprehensive Income (Loss)	8.5	(3.1)	5.4
Balance in AOCI as of September 30, 2021	$ 7.7	$ 4.9	$ 12.6

I&M

Three Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2022	$ (5.9)	$ 5.2	$ (0.7)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.3)	(0.3)
Amortization of Actuarial (Gains) Losses	—	0.1	0.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	(0.2)	0.3
Income Tax (Expense) Benefit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	(0.1)	0.3
Net Current Period Other Comprehensive Income (Loss)	0.4	(0.1)	0.3
Balance in AOCI as of September 30, 2022	$ (5.5)	$ 5.1	$ (0.4)

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2021	$ (7.4)	$ 1.2	$ (6.2)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.5	—	0.5
Amortization of Prior Service Cost (Credit)	—	(0.2)	(0.2)
Amortization of Actuarial (Gains) Losses	—	0.2	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.5	—	0.5
Income Tax (Expense) Benefit	0.1	—	0.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.4	—	0.4
Net Current Period Other Comprehensive Income (Loss)	0.4	—	0.4
Balance in AOCI as of September 30, 2021	$ (7.0)	$ 1.2	$ (5.8)

I&M

Nine Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2021	$ (6.7)	$ 5.4	$ (1.3)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.5	—	1.5
Amortization of Prior Service Cost (Credit)	—	(0.7)	(0.7)
Amortization of Actuarial (Gains) Losses	—	0.3	0.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.5	(0.4)	1.1
Income Tax (Expense) Benefit	0.3	(0.1)	0.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.2	(0.3)	0.9
Net Current Period Other Comprehensive Income (Loss)	1.2	(0.3)	0.9
Balance in AOCI as of September 30, 2022	$ (5.5)	$ 5.1	$ (0.4)

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (8.3)	$ 1.3	$ (7.0)
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.6	—	1.6
Amortization of Prior Service Cost (Credit)	—	(0.6)	(0.6)
Amortization of Actuarial (Gains) Losses	—	0.5	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.6	(0.1)	1.5
Income Tax (Expense) Benefit	0.3	—	0.3
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	(0.1)	1.2
Net Current Period Other Comprehensive Income (Loss)	1.3	(0.1)	1.2
Balance in AOCI as of September 30, 2021	$ (7.0)	$ 1.2	$ (5.8)

PSO

Three Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of June 30, 2022	$ —
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—
Net Current Period Other Comprehensive Income (Loss)	—
Balance in AOCI as of September 30, 2022	$ —

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of June 30, 2021	$ —
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—
Net Current Period Other Comprehensive Income (Loss)	—
Balance in AOCI as of September 30, 2021	$ —

Nine Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2021	$ —
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—
Net Current Period Other Comprehensive Income (Loss)	—
Balance in AOCI as of September 30, 2022	$ —

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2020	$ 0.1
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (b)	(0.1)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(0.1)
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.1)
Net Current Period Other Comprehensive Income (Loss)	(0.1)
Balance in AOCI as of September 30, 2021	$ —

SWEPCo

Three Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2022	$ 1.2	$ 4.7	$ 5.9
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—	(0.5)	(0.5)
Income Tax (Expense) Benefit	—	(0.1)	(0.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—	(0.4)	(0.4)
Net Current Period Other Comprehensive Income (Loss)	—	(0.4)	(0.4)
Balance in AOCI as of September 30, 2022	$ 1.2	$ 4.3	$ 5.5

Three Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of June 30, 2021	$ 0.5	$ 1.4	$ 1.9
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	0.4	—	0.4
Amortization of Prior Service Cost (Credit)	—	(0.5)	(0.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.4	(0.5)	(0.1)
Income Tax (Expense) Benefit	0.1	(0.1)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.3	(0.4)	(0.1)
Net Current Period Other Comprehensive Income (Loss)	0.3	(0.4)	(0.1)
Balance in AOCI as of September 30, 2021	$ 0.8	$ 1.0	$ 1.8

SWEPCo

Nine Months Ended September 30, 2022	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2021	$ 1.2	$ 5.5	$ 6.7
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—	(1.5)	(1.5)
Income Tax (Expense) Benefit	—	(0.3)	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—	(1.2)	(1.2)
Net Current Period Other Comprehensive Income (Loss)	—	(1.2)	(1.2)
Balance in AOCI as of September 30, 2022	$ 1.2	$ 4.3	$ 5.5

Nine Months Ended September 30, 2021	Cash Flow Hedge – Interest Rate	Pension and OPEB	Total
		(in millions)	
Balance in AOCI as of December 31, 2020	$ (0.3)	$ 2.2	$ 1.9
Change in Fair Value Recognized in AOCI	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Interest Expense (b)	1.4	—	1.4
Amortization of Prior Service Cost (Credit)	—	(1.5)	(1.5)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.4	(1.5)	(0.1)
Income Tax (Expense) Benefit	0.3	(0.3)	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.1	(1.2)	(0.1)
Net Current Period Other Comprehensive Income (Loss)	1.1	(1.2)	(0.1)
Balance in AOCI as of September 30, 2021	$ 0.8	$ 1.0	$ 1.8

(a) The change in fair value includes $(4) million and $(1) million, respectively, for the three months ended September 30, 2022 and 2021 and $(9) million and $(5) million, respectively, for the nine months ended September 30, 2022 and 2021 related to AEP's investment in joint venture wind farms acquired as part of the purchase of Sempra Renewables LLC.

(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.

As discussed in the 2021 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2021 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2022 and updates the 2021 Annual Report.

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

SWEPCo

In April 2016, Welsh Plant, Unit 2 was retired. As part of the 2016 Texas Base Rate Case, the PUCT authorized recovery of SWEPCo's Texas jurisdictional share of Welsh Plant, Unit 2, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $7 million in 2017. See "2016 Texas Base Rate Case" section below 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. See "2020 Louisiana Base Rate Case" section below for additional information. As of September 30, 2022, SWEPCo had a regulatory asset for plant retirement costs pending approval recorded on its balance sheet of $35 million related to the Louisiana jurisdictional share of Welsh Plant, Unit 2.

In December 2021, the Dolet Hills Power Station was retired. As part of the 2020 Texas Base Rate Case, the PUCT authorized recovery of SWEPCo's Texas jurisdictional share of the Dolet Hills Power Station, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $12 million in 2021. As part of the 2021 Arkansas Base Rate Case, the APSC authorized recovery of SWEPCo's Arkansas jurisdictional share of the Dolet Hills Power Station over five years, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $2 million in the second quarter of 2022. Also, the APSC did not rule on the prudency of the early retirement of the Dolet Hills Power Station, which will be addressed in a future proceeding. SWEPCo has requested recovery of the Dolet Hills Power Station in the Louisiana jurisdiction through the 2020 Louisiana Base Rate Case. As of September 30, 2022, SWEPCo had a regulatory asset of $5 million, pending approval, recorded on its balance sheet related to the Louisiana and FERC jurisdictional shares of the Dolet Hills Power Station. The Dolet Hills Power Station is currently being recovered through 2026 in the Louisiana jurisdiction, through 2027 in the Arkansas jurisdiction and through 2046 in the Texas jurisdiction. See "2020 Texas Base Rate Case", "2020 Louisiana Base Rate Case" and "2021 Arkansas Base Rate Case" sections below for additional information.

Regulated Generating Units to be Retired

PSO

In 2014, PSO received final approval from the Federal 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. As part of the 2021 Oklahoma Base Rate Case, PSO will continue to recover Northeastern Plant, Unit 3 through 2040.

SWEPCo

In November 2020, management announced plans to retire Pirkey 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 September 30, 2022, of generating facilities planned for early retirement:

Plant	Net Book Value	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	$ 143.7	$ 141.4	$ 20.2	(b)	2026	(c)	$ 14.9
Pirkey Plant	65.0	150.7	39.6		2023	(d)	12.5
Welsh Plant, Units 1 and 3	432.3	75.7	58.2	(e)	2028	(f)	39.8

(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) Pirkey Plant is currently being recovered through 2025 in the Louisiana jurisdiction and through 2045 in the Arkansas and Texas jurisdictions.
(e) 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.
(f) 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)

In 2020, 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. In April 2020, SWEPCo and CLECO jointly filed a notification letter to the LPSC providing notice of the cessation of lignite mining. In December 2021, the Dolet Hills Power Station was retired. While in operation, DHLC provided 100% of the fuel supply to Dolet Hills Power Station.

The remaining book value of Dolet Hills Power Station non-fuel related assets are recoverable by SWEPCo through a combination of base rates and rate riders. As of September 30, 2022, SWEPCo's share of the net investment in the Dolet Hills Power Station was $13 million, including materials and supplies, net of cost of removal collected in rates.

Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses and are subject to prudency determinations by the various commissions. After closure of the DHLC mining operations and the Dolet Hills Power Station, additional reclamation and other land-related costs incurred by DHLC and Oxbow will continue to be billed to SWEPCo and included in existing fuel clauses. As of September 30, 2022, SWEPCo had a net under-recovered fuel balance of $236 million, inclusive of costs related to the Dolet Hills Power Station billed by DHLC, but excluding impacts of the February 2021 severe winter weather event.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to $20 million of fuel costs in 2021 and defer approximately $30 million of additional costs with a recovery period to be determined at a later date. In August 2022, the LPSC staff filed testimony recommending fuel disallowances of $72 million, including denial of recovery of the $30 million deferral, with refunds to customers over five years. In September 2022, SWEPCO filed rebuttal testimony addressing the LPSC staff recommendations.

In March 2021, the APSC approved fuel rates that provide recovery of $20 million for the Arkansas share of the 2021 Dolet Hills Power Station fuel costs over five years through the existing fuel clause.

In August 2022, SWEPCo filed a fuel reconciliation with the PUCT covering the fuel period of January 1, 2020 through December 31, 2021.

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

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

In 2020, management announced plans to retire the Pirkey Plant in 2023. The Pirkey Plant non-fuel costs are recoverable by SWEPCo through base rates and fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions. As of September 30, 2022, SWEPCo's share of the net investment in the Pirkey Plant was $216 million, including CWIP, before cost of removal. Sabine is a mining operator providing mining services to the Pirkey 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 $49 million as of September 30, 2022. As of September 30, 2022, SWEPCo had a net under-recovered fuel balance of $236 million, inclusive of costs related to the Pirkey Plant billed by Sabine, but excluding impacts of the February 2021 severe winter weather event. Upon cessation of lignite deliveries by Sabine to the Pirkey Plant, additional operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in existing fuel clauses. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

Noncurrent Regulatory Assets	AEP September 30, 2022	AEP December 31, 2021
	(in millions)	
Regulatory Assets Currently Earning a Return		
Pirkey Plant Accelerated Depreciation	$ 150.7	$ 87.0
Unrecovered Winter Storm Fuel Costs (a)	126.1	430.2
Welsh Plant, Units 1 and 3 Accelerated Depreciation	75.7	45.9
Dolet Hills Power Station Accelerated Depreciation	54.7	72.3
Plant Retirement Costs – Unrecovered Plant, Louisiana	35.2	35.2
Dolet Hills Power Station Fuel Costs - Louisiana	31.8	30.9
Other Regulatory Assets Pending Final Regulatory Approval	21.2	9.2
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	306.5	241.8
2017-2019 Virginia Triennial Under-Earnings	37.0	—
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	25.9
2020-2022 Virginia Triennial Under-Earnings	25.3	15.1
COVID-19	8.7	11.2
Renewable Energy Portfolio Standards Costs - Virginia	—	2.1
Other Regulatory Assets Pending Final Regulatory Approval	42.4	41.8
Total Regulatory Assets Pending Final Regulatory Approval	$ 941.2	$ 1,048.6

(a) Includes $37 million and $63 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of September 30, 2022 and December 31, 2021, respectively.

Noncurrent Regulatory Assets	AEP Texas September 30, 2022	AEP Texas December 31, 2021
	(in millions)	
Regulatory Assets Currently Earning a Return		
Mobile Generation Lease Payments	$ 9.2	$ —
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	27.0	22.4
Vegetation Management Program	5.2	5.2
Texas Retail Electric Provider Bad Debt Expense	4.1	4.1
COVID-19	3.8	2.1
Other Regulatory Assets Pending Final Regulatory Approval	8.2	7.4
Total Regulatory Assets Pending Final Regulatory Approval	$ 57.5	$ 41.2

Noncurrent Regulatory Assets	APCo September 30, 2022	APCo December 31, 2021
	(in millions)	
Regulatory Assets Currently Earning a Return		
COVID-19 – Virginia	$ 7.0	$ 6.8
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs - West Virginia	69.9	53.7
2017-2019 Virginia Triennial Under-Earnings	37.0	—
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	25.9
2020-2022 Virginia Triennial Under-Earnings	25.3	15.1
Renewable Energy Portfolio Standards Costs - Virginia	—	2.1
Other Regulatory Assets Pending Final Regulatory Approval	1.6	1.5
Total Regulatory Assets Pending Final Regulatory Approval	$ 166.7	$ 105.1

Noncurrent Regulatory Assets	I&M September 30, 2022	I&M December 31, 2021
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.1	$ 0.1
Regulatory Assets Currently Not Earning a Return		
COVID-19	0.1	1.7
Other Regulatory Assets Pending Final Regulatory Approval	1.7	1.9
Total Regulatory Assets Pending Final Regulatory Approval	$ 1.9	$ 3.7

Noncurrent Regulatory Assets	OPCo September 30, 2022	OPCo December 31, 2021
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 32.5	$ 3.8
Other Regulatory Assets Pending Final Regulatory Approval	0.1	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 32.6	$ 3.8

Noncurrent Regulatory Assets	PSO September 30, 2022	PSO December 31, 2021
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 24.3	$ 13.9
Other Regulatory Assets Pending Final Regulatory Approval	0.1	0.3
Total Regulatory Assets Pending Final Regulatory Approval	$ 24.4	$ 14.2

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Noncurrent Regulatory Assets	SWEPCo September 30, 2022	SWEPCo December 31, 2021
	(in millions)	
Regulatory Assets Currently Earning a Return		
Pirkey Plant Accelerated Depreciation	$ 150.7	$ 87.0
Unrecovered Winter Storm Fuel Costs (a)	126.1	430.2
Welsh Plant, Units 1 and 3 Accelerated Depreciation	75.7	45.9
Dolet Hills Power Station Accelerated Depreciation	54.7	72.3
Plant Retirement Costs – Unrecovered Plant, Louisiana	35.2	35.2
Dolet Hills Power Station Fuel Costs- Louisiana	31.8	30.9
Other Regulatory Assets Pending Final Regulatory Approval	4.9	2.4
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	151.3	148.0
Asset Retirement Obligation - Louisiana	11.3	10.3
Other Regulatory Assets Pending Final Regulatory Approval	14.9	18.4
Total Regulatory Assets Pending Final Regulatory Approval	$ 656.6	$ 880.6

(a) Includes $37 million and $63 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of September 30, 2022 and December 31, 2021, respectively.

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

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

AEP Texas Interim Transmission and Distribution Rates

Through September 30, 2022, AEP Texas' cumulative revenues from interim base rate increases that are subject to review is approximately $524 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 5, 2024.

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

2017-2019 Virginia Triennial Review

In November 2020, the Virginia SCC issued an order on APCo's 2017-2019 Triennial Review filing 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 prospective9.2% ROE for APCo's 2020-2022 triennial review period with the continuation of a140 basis point band (8.5% bottom, 9.2% midpoint, 9.9% top).

In March 2021, APCo filed an appeal with the Virginia Supreme Court related to the November 2020 order in which it stated the Virginia SCC erred (a) in finding that costs associated with asset impairments related to early retirement determinations made by APCo for certain generation facilities should not be attributed to the test periods under review and deemed fully recovered in the period recorded, (b) in finding that it was permitted to evaluate the reasonableness of APCo's decision to record, per books for financial reporting purposes, asset impairments related to early retirement determinations for certain generation facilities, (c) as a result of the errors described in (a) and (b), in denying APCo an increase in rates, (d) in failing to review and make any findings regarding whether APCo's rates would allow it to earn a fair rate of return going forward, (e) in denying APCo an increase in base rates by failing to ensure that APCo has an opportunity to recover its costs and earn a fair rate of return, thereby resulting in a taking of private property for public use without just compensation and (f) in retroactively adjusting APCo's depreciation expense for purposes of calculating APCo's earnings for the 2017-2019 triennial period.

In October 2021, the Virginia SCC and additional intervenors filed briefs with the Virginia Supreme Court disagreeing with the items appealed by APCo in the Triennial Review decision. Additionally, the Virginia SCC and APCo filed briefs disagreeing with the items appealed by an intervenor in a separate appeal of the same decision. In March 2022, oral arguments were held at the Virginia Supreme Court.

In August 2022, the Virginia Supreme Court issued its opinion on submitted appeals of APCo's 2017-2019 Virginia Triennial Review concluding that the Virginia SCC: a) erred in finding it was not reasonable for APCo to record all remaining costs associated with early retirement of certain coal-fired generating plants in the 2017-2019 earnings test period, b) did not err by ordering APCo to retroactively implement depreciation rates for the years 2018 and 2019 and c) did not err in finding that APCo's affiliate costs from OVEC were reasonable.The Virginia Supreme Court then remanded the issue regarding the retired coal-fired plants back to the Virginia SCC for further proceedings.

In September 2022, and in response to the Virginia Supreme Court opinion and subsequent Virginia SCC order initiating a remand proceeding, APCo submitted with the Virginia SCC: (a) an updated 2017-2019 Virginia earnings calculation resulting in a proposed $37 million regulatory asset related to previously incurred costs that APCo is expecting to recover as a result of earning below its 2017-2019 authorized ROE band, (b) an updated requested annual base rate increase of $41 million effective October 2022 and (c) a requested rider to recover, over the period October 2022 through January 2024, approximately $72 million related to an APCo Virginia base rate increase for the period January 2021 through September 2022.APCo's requested $41 million annual base rate increase includes approximately $12 million related to the recovery of APCo’s regulatory asset for previously incurred costs as a result of earning below its 2017-2019 authorized ROE band. APCo implemented interim base rate and rider rate increases effective October 2022, both of which are subject to refund and review by the Virginia SCC. An order from the Virginia SCC in the remand proceeding is expected in the fourth quarter of 2022.

In September 2022, APCo expensed the remaining $25 million closed coal plant regulatory asset that was previously ordered by the Virginia SCC and recorded a $37 million regulatory asset for previously incurred costs that APCo is expecting to recover as a result of earning below its 2017-2019 authorized ROE band. APCo’s October 2022 through January 2024 net income, cash flows and financial condition is expected to be positively impacted pending the Virginia SCC’s order on APCo’s requested base rate and rider rate increases.

2020-2022 Virginia Triennial Review

In March 2023, APCo will submit its required Virginia earnings test calculation for the 2020-2022 Triennial Review period. For Triennial Review periods in which a Virginia utility earns below its authorized ROE band, the utility may file to recover expenses incurred, up to the bottom of the authorized ROE band, related to major storms, the early retirement of fossil fuel generating assets and certain projects necessary to comply with state and federal environmental legislation. As of September 2022, APCo has deferred approximately $25 million related to previously incurred costs as a result of the current estimate that APCo will earn below the bottom of its authorized ROE band during the 2020-2022 Triennial Review period. If it is determined that APCo has earned above the bottom of its authorized ROE band for the 2020-2022 Triennial Review period it could reduce future net income and cash flows and impact financial conditions.

CCR/ELG Compliance Plan Filings

In December 2020, APCo submitted filings with the Virginia SCC and WVPSC requesting approvals necessary to implement CCR/ELG complianc plans at the Amos and Mountaineer Plants. In August 2021, the Virginia SCC issued an order approving recovery of CCR-related operation and maintenance expenses and investments at the Amos and Mountaineer Plants through an active rider. The order also denied APCo’s request to recover the cost of ELG investments and denied recovery of previously incurred ELG costs, but did not preclude APCo from refiling for approval. In March 2022, APCo refiled for approval to recover the cost of the ELG investments and previously incurred ELG costs. Intervenor testimony was submitted in August 2022 recommending the denial of ELG cost recovery. In October 2022, a Virginia Hearing Examiner recommended that the Virginia SCC approve recovery of APCo’s requested ELG investment costs at Amos and Mountaineer Plants. Management expects to receive an order from the Virginia SCC in the fourth quarter of 2022.

Also in August 2021, the WVPSC approved the request to construct CCR/ELG investments at the Amos and Mountaineer Plants and approve recovery of the West Virginia jurisdictional share of these costs through an active rider. In October 2021, due to the Virginia SCC previously rejecting those ELG investments, the WVPSC issued an order directing APCo to proceed with CCR/ELG compliance plans that would allow the plants t continue operating beyond 2028. The WVPSC also ordered that APCo will be given the opportunity to recover, from West Virginia customers, the ELG and new capital and operating costs arising solely from the WVPSC's directive to operate the plants beyond 2028 if the WVPSC finds that th costs are reasonably and prudently incurred. The October 2021 order further states that unless the Virginia jurisdictional customers of APCo pay for their share of costs for ELG improvements and costs necessary to continue operations beyond 2028, the benefit of the capacity and energy made possible by those improvements and operating the Amos and Mountaineer Plants beyond 2028 should benefit only West Virginia and FERC jurisdictional customers who have shared in paying for those costs.

APCo expects the total Amos and Mountaineer Plant ELG investment, excluding AFUDC, to be approximately $162 million. As of September 30, 2022, APCo’s Virginia jurisdictional share of the net book value, before cost of removal including CWIP and inventory, of the Amos and Mountaineer Plants was approximately $1.5 billion and APCo’s Virginia jurisdictional share of its ELG investment balance in CWIP for these plants was $62 million.

If any of the ELG costs are not approved for recovery and/or the retirement dates of the Amos and Mountaineer Plants are accelerated to 2028 without commensurate cost recovery, it would reduce future net income and cash flows and impact financial condition.

2021 and 2022 ENEC (Expanded Net Energy Cost) Filings

In April 2021, APCo and WPCo (the Companies) requested a $3 million annual increase in ENEC rates based on a cumulative combined $55 million ENEC under-recovery as of February 28, 2021 and a combined $18 million increase in projected ENEC costs for the period September 2021 through August 2022. In September 2021, the WVPSC issued an order approving a $7 million overall increase in ENEC rates, including an approval for recovery of the Companies' cumulative $55 million ENEC under-recovery balance and a $48 million reduction in projected costs for the period September 2021 through August 2022. Subsequently, the Companies submitted a request for reconsideration of this order, identifying flaws in the WVPSC's calculation of forecasted future year fuel expense and purchased power costs.

In March 2022, the WVPSC issued an order granting the Companies' request for reconsideration, in part, and approving $1 million in projected costs for the period September 2021 through August 2022. The order also reopened the 2021 ENEC case to require the Companies to explain the significant growth in the reported under-recovery of ENEC costs and to provide various other information including revised projected costs for the period March 2022 through August 2022. Also, in March 2022, the Companies filed testimony providing the information requested in the WVPSC's order and requested a $155 million annual increase in ENEC rates effective May 1, 2022.In May 2022, the WVPSC issued an order approving a $93 million overall increase to ENEC rates to recover projected annual ENEC costs. However, the WVPSC stated that actual and projected ENEC costs are st subject to a prudency review.

In April 2022, the Companies submitted their 2022 annual ENEC filing with the WVPSC requesting a $297 million annual increase in ENEC revenues, inclusive of the previously requested $155 million increase, effective September 1, 2022.

In September 2022, following an agreed upon delay in the proceedings of the Companies' 2022 ENEC case, certain intervenors submitted testimony recommending disallowances of at least $83 million to the Companies' historical period ENEC under-recovery balance along with proposals to either securitize the Companies' remaining ENEC balance or defer recovery of this balance beyond the traditional one-year period.West Virginia Staff recommended a $13 million increase in ENEC rates pending the outcome of the ENEC prudency reviewManagement expects to receive a WVPSC order on the Companies' 2022 ENEC filing in the fourth quarter of 2022 and a separate WVPSC order on the prudency review of the Companies' ENEC costs in the first quarter of 2023.As of September 30, 2022, the Companies' cumulative ENEC under-recovery was $430 million. If any deferred ENEC costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

June 2022 West Virginia Storm Costs

In June 2022, the West Virginia service territories of APCo and WPCo (the Companies) were impacted by strong winds from multiple storms resulting in system damages and power outages. As of September 30, 2022, the Companies incurred and deferred an estimated $15 million in incremental distribution operation and maintenance expenses related to service restoration efforts. The Companies will seek recovery of these deferrals in future filings. If any of the storm restoration costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next base rate proceeding. Through September 30, 2022, AEP's share of ETT's cumulative revenues that are subject to review is approximately $1.5 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. ETT is required to file for a comprehensive rate review no later than February 1, 2023, during which the $1.5 billion of cumulative revenues above will be subject to review.

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

Michigan Power Supply Cost Recovery (PSCR) Reconciliation

In April 2022, an Administrative Law Judge (ALJ) issued a Proposal for Decision (PFD) for I&M's PSCR reconciliation for the 12-month perio ending December 31, 2020, recommending the MPSC disallow approximately $8 million of purchased power costs that I&M incurred under the Inter-Company Power Agreement with OVEC and the Unit Power Agreement with AEGCo. In May 2022, I&M submitted exceptions to the ALJ's PFD related to the recommended disallowance of purchased power costs described above. I&M anticipates that the MPSC will issue a final decision in the fourth quarter of 2022. Management is unable to predict the impact, if any, that the MPSC's final decision may have on future results of operations, financial condition and cash flows.

Indiana Earnings Test Filings

I&M is required by Indiana law to submit an earnings test evaluation for the most recent one-year and five-year periods as part of I&M's semi-annual Indiana FAC filings. These earnings test evaluations require I&M to include a credit in the FAC factor computation for periods in which I&M earned above its authorized return for both the one-year and five-year periods. The credit is determined as 50% of the lower of the one-year or five-year earnings above the authorized level. In August 2022, I&M submitted its FAC filing and earnings test evaluation for the period ended May 2022, which calculated a credit due to customers of $14 million. In October 2022, the IURC approved the FAC filing and earnings test evaluation, with the credit to customers starting in November 2022 through the FAC.

2022 Michigan Integrated Resource Plan (IRP) Filing

In February 2022, I&M filed a request with the MPSC for approval of its 2022 IRP. Included in that filing were requests for approval and deferral of costs associated with resources commencing construction within three years of the Commission's order in the filing. These resources include the new generation resources expected to be in-service by 2028, and demand-side resources, including load management programs and conservation voltage reduction investments. I&M is also requesting MPSC approval of I&M's Rockport Unit 2 transition plan consistent with that approved by the IURC including certain cost recovery related to remaining net book value of leasehold improvements made during the term of the Rockport Unit 2 lease and future use of Rockport Unit 2 as a capacity resource. In addition, I&M has made requests for approval of a financial incentive on certain power purchase agreements and load management programs. As of September 30, 2022, I&M's total net book value for these Rockport Unit 2 leasehold improvements was $102 million.

In June 2022, intervening parties recommended various adjustments to I&M's proposals, including the process I&M would use to receive approval of new generation resources, changes to or denial of requested financial incentives and requests for deferral and pre-approval of costs. Specific to I&M's Rockport Unit 2 transition plan, certain intervening parties recommended that the MPSC order I&M to credit back to Michigan ratepayers the jurisdictional share of post-lease revenues in excess of costs from Rockport Unit 2's operations as a merchant facility and that I&M only receive a post-lease debt return on remaining net book value of Rockport Unit 2 leasehold improvements. A hearing with the MPSC was held in August 2022.

Management currently anticipates that the MPSC will issue an order on I&M's 2022 Michigan IRP filing in the first quarter of 2023. Any disallowance or reduction in the recovery of the I&M Michigan jurisdictional share of the Rockport Unit 2 leasehold improvements could reduce future net income and cash flows and impact financial condition.

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

CCR/ELG Compliance Plan Filings

KPCo and WPCo each own a 50% interest in the Mitchell Plant. As of September 30, 2022, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $576 million. 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 CCR and ELG compliance plans an seek recovery of the estimated $132 million investment for the Mitchell Plant that would allow the plant to continue operating beyond 2028. Within those requests, WPCo and KPCo also filed a $25 million alternative to implement only the CCR-related investments with the WVPSC and KPSC respectively, which would allow the Mitchell Plant to continue operating only through 2028.

In July 2021, the KPSC issued an order approving the CCR only alternative and rejecting the full CCR and ELG compliance plan. In May 2022, the KPSC approved recovery of the Kentucky jurisdictional share of ELG costs incurred at the Mitchell Plant prior to July 15, 2021.

In August 2021, the WVPSC approved the full CCR and ELG compliance plan for the WPCo share of the Mitchell Plant. In September 2021, WP(submitted a filing with the WVPSC to reopen the CCR/ELG case that was approved by the WVPSC in August 2021. Due to the rejection by th KPSC of the KPCo share of the ELG investments, WPCo requested the WVPSC consider approving the construction and recovery of all ELG cos at the plant. In October 2021, the WVPSC affirmed its August 2021 order approving the construction of CCR/ELG investments and directed WPC to proceed with CCR/ELG compliance plans that would allow the plant to continue operating beyond 2028. The WVPSC also ordered that WPCo will be given the opportunity to recover, from its customers, the ELG and new capital and operating costs arising solely from the WVPSC's directive to operate the plant beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred. The WVPSC's order further states that unless KPCo pays for its share of costs for ELG improvements and costs necessary to continue operations beyond 2028, the benefit of the capacity and energy made possible by those improvements and operating Mitchell Plant beyond 2028 should benefit only West Virginia jurisdictional customers who have shared in paying for those costs.

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

OVEC Cost Recovery Audits

In December 2021, as part of OVEC cost recovery audits pending before the PUCO, intervenors filed positions claiming that costs incurred by OPC during the 2018-2019 audit period were imprudent and should be disallowed. In May 2022, intervenors filed for rehearing on the 2016-2017 OVEC cost recovery audit period claiming the PUCO's April 2022 order to adopt the findings of the audit report were unjust, unlawful and unreasonable for multiple reasons, including the position that OPCo recovered imprudently incurred costs. In June 2022, the PUCO granted rehearing on the 2016-2017 audit period for purposes of further consideration. Management disagrees with these claims and is unable to predict the impact, if any, these disputes may have on future results of operations, financial condition and cash flows. See "OVEC" section of Note 17 in the 2021 Annual Report for additional information on AEP and OPCo's investment in OVEC.

June 2022 Storm Costs

In June 2022, the service territory of OPCo was impacted by strong winds from multiple storms resulting in power outages and damage to the transmission and distribution infrastructures. As of September 30, 2022, OPCo had incurred approximately $19 million in incremental operation and maintenance costs related to service restoration efforts. The incremental storm restoration costs have been deferred as regulatory assets and OPCo is expected to seek recovery in a future filing. In July 2022, intervenors filed a motion requesting the PUCO open a formal investigation into the power outages that occurred as a result of the June storms and determine if OPCo was negligent and liable to consumers for damages incurred as a result of the power outages. If any of the storm restoration costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

PSO Rate Matters (Applies to AEP and PSO)

February 2021 Severe Winter Weather Impacts in SPP

In February 2021, severe winter weather 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.

In April 2021, the OCC approved a waiver allowing the deferral of PSO's extraordinary fuel costs and purchases of electricity as regulatory assets, including a carrying charge at an interim rate of 0.75%, over a longer time period than what the FAC traditionally allows. Also in April 2021, legislation was enacted in Oklahoma permitting securitized financing of qualified costs from extreme weather events. This legislation provides certain authority to the OCC to approve amounts to be recovered from the issuance of ratepayer-backed securitized bonds issued by the ODFA, an Oklahoma governmental agency. In January 2022, PSO, OCC staff and certain intervenors filed a joint stipulation and settlement agreement with the OCC to approve the securitization of PSO's extraordinary fuel costs and purchases of electricity. In February 2022, the OCC approved the joint stipulation and settlement agreement which included a determination that all of PSO's extraordinary fuel costs and purchases of electricity were prudent and reasonable and also provided a 0.75% carrying charge related to those costs, subject to true-up based on actual financing costs.

In September 2022, PSO received proceeds of $687 million from the ODFA which issued ratepayer-backed securitization bonds for the purpose of reimbursing PSO for extraordinary fuel costs and purchases of electricity incurred during the February 2021 severe winter weather event, which were previously recorded as Regulatory Assets on PSO's balance sheet. The securitization bonds are the obligation of the ODFA and there is no recourse against PSO in the event of a bond default, and therefore are not recorded as Long-term Debt on PSO's balance sheet. PSO will serve as the servicing agent of the bonds and is responsible for the routine billing and collection of the securitization charges and remitting those collections back to the ODFA. The securitization charges billed to and collected from customers are not included as revenue on PSO's statement of income. The collections from customers will occur over 20 years.

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

2012 Texas Base Rate Case

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

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of a previously recorded regulatory disallowance in 2013. 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 March 2021, the Texas Supreme Court issued an opinion reversing the July 2018 judgment of the Texas Third Court of Appeals and agreeing with the PUCT's judgment affirming the prudence of the Turk Plant. In addition, the Texas Supreme Court remanded the AFUDC dispute back to the Texas Third Court of Appeals. No parties filed a motion for rehearing with the Texas Supreme Court. In August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgment affirming the PUCT's order on AFUDC, concluding that the language of the PUCT's original 2008 order intended to include AFUDC in the Texas jurisdictional capital cost cap, and remanded the case to the PUCT for future proceedings. SWEPCo disagrees with the Court of Appeals decision. SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court in November 2021. In October 2022, the Texas Supreme Court denied the Petitions for Review submitted by SWEPCo and the PUCT. SWEPCo plans to file a request for rehearing. If SWEPCo's request for rehearing is denied, the case will be remanded to the PUCT for future proceedings.

Management does not believe a disallowance of capitalized Turk Plant costs or a revenue refund is probable as of September 30, 2022. However, if SWEPCo is ultimately unable to recover AFUDC in excess of the Texas jurisdictional capital cost cap, it would be expected to result in a pretax net disallowance ranging from $80 million to $90 million. In addition, if AFUDC is ultimately determined to be included in the Texas jurisdictional capital cost cap, SWEPCo estimates it may be required to make customer refunds ranging from $0 to $180 million related to revenues collected from February 2013 through September 2022 and such determination may reduce SWEPCo's future revenues by approximately $15 million on an annual basis.

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. The appeal will move forward following the conclusion of the 2012 Texas Base Rate Case. If certain parts of the PUCT order are overturned, 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. SWEPCo subsequently filed a request with the PUCT lowering the requested annual increase in Texas base rates to $100 million which would result in an $85 million net annual base rate increase after moving the proposed riders to rate base.

In January 2022, the PUCT issued a final order approving an annual revenue increase of $39 million based upon a 9.25% ROE. The order also includes: (a) rates implemented retroactively back to March 18, 2021, (b) $5 million of the proposed increase related to vegetation management, (c) $2 million annually to establish a storm catastrophe reserve and (d) the creation of a rider that would recover the Dolet Hills Power Station as if it were in rate base until its retirement at the end of 2021 and starting in 2022 the remaining net book value would be recovered as a regulatory asset through 2046. As a result of the final order, SWEPCo recorded a disallowance of $12 million in 2021 associated with the lack of return on the Dolet Hills Power Station. In February 2022, SWEPCo filed a motion for rehearing with the PUCT challenging several errors in the order, which include challenges of the approved ROE, the denial of a reasonable return or carrying costs on the Dolet Hills Power Station and the calculation of the Texas jurisdictional share of the storm catastrophe reserve. In April 2022, the PUCT denied the motion for rehearing. In May 2022, SWEPCo filed a petition for review with the Texas District Court seeking a judicial review of the several errors challenged in the PUCT's final order.

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. SWEPCo subsequently revised the requested annual increase to $114 million to reflect removing hurricane storm restoration costs from the base case filing. The hurricane costs have been requested in a separate storm filing. See "2021 Louisiana Storm Cost Filing" below for more information. The base case filing 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 requests a $32 million annual depreciation increase to recover Louisiana's share of the Dolet Hills Power Station, Pirkey Plant and Welsh Plant, all of which are expected to be retired early.

In July 2021, the LPSC staff filed testimony supporting a $6 million annual increase in base rates based upon a ROE of 9.1% while other intervenors recommended a ROE ranging from 9.35% to 9.8%. The primary differences between SWEPCo's requested annual increase in base rates and the LPSC staff's recommendation include: (a) a reduction in depreciation expense, (b) recovery of Dolet Hills Power Station and Pirkey Plant in a separate rider mechanism, (c) the rejection of SWEPCo's proposed adjustment to include a stand-alone net operating loss carryforward deferred tax asset in rate base and (d) a reduction in the proposed ROE. In August 2022, in a separate proceeding, the LPSC staff recommended recovery of, but no return on, the Dolet Hills Power Station based on a five-year recovery period if the remaining net book value is not recovered utilizing securitization. Additionally, the LPSC staff recommended that the remaining net book value be reduced for depreciation expenses, and operation and maintenance costs in rates since the plant was retired in December 2021.

In September 2021, SWEPCo filed rebuttal testimony supporting a revised requested annual increase in base rates of $95 million. The primary differences in the rebuttal testimony from the previous revised request of $114 million are modifications to the proposed recovery of the Dolet Hills Power Station and revisions to various proposed amortizations. LPSC staff and intervenor responses to SWEPCo's rebuttal testimony were filed in October 2021.The procedural schedule for the case is on hold due to ongoing settlement discussions.

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

2021 Arkansas Base Rate Case

In July 2021, SWEPCo filed a request with the APSC for an $85 million annual increase in Arkansas base rates based upon a proposed 10.35% ROE with a capital structure of 48.7% debt and 51.3% common equity. The proposed annual increase includes: (a) a $41 million revenue requirement for the North Central Wind Facilities, (b) a $14 million annual depreciation increase primarily due to recovery of the Dolet Hills Power Station through 2026 and Pirkey Plant and Welsh Plant, Units 1 and 3 through 2037 and (c) a $6 million increase due to SPP costs. In January 2022, SWEPCo filed testimony revising the requested annual increase in Arkansas base rates to $81 million. SWEPCo requested that rates become effective in June 2022.

In May 2022, the APSC issued a final order approving an annual revenue increase of $49 million based upon a 9.5% ROE. The order also includes: (a) a capital structure of 55% debt and 45% common equity, (b) approval to recover the Dolet Hills Power Station as a regulatory asset over five years without a return on this investment resulting in an immaterial disallowance in the second quarter of 2022, (c) the denial of accelerated depreciation for the Pirkey Plant and Welsh Plant, Units 1 and 3 and (d) approval of a rider to recover SPP costs and revenues.The final order also denied the inclusion of the stand-alone NOLC in SWEPCo's deferred tax assets, but included approval of the deferral of the forgone revenue requirement associated with the NOLC and excess NOLC, with recovery of the deferral contingent upon receipt of a supportive private letter ruling from the IRS. Rates were implemented with the first billing cycle of July 2022.

2021 Louisiana Storm Cost Filing

In 2020, Hurricanes Laura and Delta caused power outages and extensive damage to the SWEPCo service territories, primarily impacting the Louisiana jurisdiction. Following both hurricanes, the LPSC issued orders allowing Louisiana utilities, including SWEPCo, to establish regulatory assets to track and defer expenses associated with these storms. In February 2021, severe winter weather impacted the Louisiana jurisdiction and in March 2021, the LPSC approved the deferral of incremental storm restoration expenses related to the winter storm.In October 2021, SWEPCo filed a request with the LPSC for recovery of $145 million in deferred storm costs associated with the three storms. As part of the filing, SWEPCo requested recovery of the carrying charges on the deferred regulatory asset at a weighted average cost of capital through a rider beginning in January 2022. In May 2022, LPSC staff testimony was submitted to the LPSC.In July 2022, SWEPCo filed rebuttal testimony which agreed to make a request for securitization as the LPSC staff had recommended in their testimony.An order is expected before the end of 2022. 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

As discussed in the "PSO Rate Matters" section above, severe winter weather had a significant impact in SPP, resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. For the time period of February 9, 2021, to February 20, 2021, SWEPCo's natural gas expenses and purchases of electricity still to be recovered from customers are $349 million as of September 30, 2022, of which $85 million, $126 million and $138 million is related to the Arkansas, Louisiana and Texas jurisdictions, respectively.

In March 2021, the APSC issued an order authorizing recovery of the Arkansas jurisdictional share of the retail customer fuel costs over five years, with the appropriate carrying charge to be determined at a later date. Subsequently, SWEPCo began recovery of these fuel costs.In April 2021, SWEPCo filed testimony supporting a five-year recovery with a carrying charge of 6.05%. In June 2022, the APSC ordered SWEPCo to recover the Arkansas jurisdictional share of the fuel costs over six years with a carrying charge equal to its weighted average cost of capital, subject to a prudency review and true-up.

In March 2021, the LPSC approved a special order granting a temporary modification to the FAC and shortly after SWEPCo began recovery of its Louisiana jurisdictional share of these fuel costs based on a five-year recovery period inclusive of an interim carrying charge of 3.25%. SWEPCo will work with the LPSC to finalize the actual recovery period and determine the appropriate carrying charge in future proceedings.

In August 2021, SWEPCo filed an application with the PUCT to implement a net interim fuel surcharge for the Texas jurisdictional share of these retail fuel costs. The application requested a five-year recovery with a carrying charge of 7.18%. In March 2022, the PUCT ordered SWEPCo to recover the Texas jurisdictional share of the fuel costs over five years with a carrying charge of 1.65% and ordered SWEPCo to file a fuel reconciliation addressing fuel costs from January 1, 2020 through December 31, 2021.

If SWEPCo is unable to recover any of the costs relating to the extraordinary fuel and purchases of electricity, or obtain authorization of a reasonable carrying charge on these costs, it could reduce future net income and cash flows and impact financial condition.

FERC Rate Matters

FERC SPP Transmission Formula Rate Challenge (Applies to AEP, AEPTCo, PSO and SWEPCo)

In May 2021, certain joint customers submitted a formal challenge at the FERC related to the 2020 Annual Update of the 2019 SPP Transmission Formula Rates of the AEP transmission owning subsidiaries within SPP.In March 2022, the FERC issued an order on the formal challenge which ruled in favor of the joint customers on several issues. Management has determined that the result of the order will have an immaterial impact to the financial statements of AEP, AEPTCo, PSO and SWEPCo.

Independence Energy Connection Project (Applies to AEP)

In 2016, PJM approved the Independence Energy Connection Project (IEC) and included it in its Regional Transmission Expansion Plan to alleviate congestion. Transource Energy has an ownership interest in the IEC, which is located in Maryland and Pennsylvania.In June 2020, the Maryland Public Service Commission approved a Certificate of Public Convenience and Necessity to construct the portion of the IEC in Maryland.In May 2021, the Pennsylvania Public Utility Commission (PAPUC) denied the IEC certificate for siting and construction of the portion in Pennsylvania Transource Energy appealed the PAPUC ruling in Pennsylvania state court and challenged the ruling before the United States District Court for the Middle District of Pennsylvania.In May 2022, the Pennsylvania state court issued an order affirming the PAPUC decision.The PAPUC decision remains subject to the jurisdiction and review of the United States District Court for the Middle District of Pennsylvania, which had stayed review of the PAPUC decision until the Pennsylvania state court had ordered.The procedural schedule for this case states that a decision by the United States District Court for the Middle of Pennsylvania will not be reached until 2023.

In September 2021, PJM notified Transource Energy that the IEC was suspended to allow for the regulatory and related appeals process to proceed in an orderly manner without breaching milestone dates in the project agreement. At that time, PJM stated that the IEC has not been cancelled and remains necessary to alleviate congestion. PJM continues to evaluate reliability and market efficiency in the area.As of September 30, 2022, AEP’s share of IEC capital expenditures was approximately $83 million, located in Total Property, Plant and Equipment - Net on AEP’s balance sheets.The FERC has previously granted abandonment benefits for this project, allowing the full recovery of prudently incurred costs if the project is cancelled for reasons outside the control of Transource Energy. If any of the IEC costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC RTO Incentive Complaint (Applies to AEP, AEPTCo and OPCo)

In February 2022, the Office of the Ohio Consumers' Counsel filed a complaint against AEPSC, American Transmission Systems, Inc. and Duke Energy Ohio, alleging the 50 basis point RTO incentive included in Ohio Transmission Owners' respective transmission formula rates is not just and reasonable and therefore should be eliminated on the basis that RTO participation is not voluntary, but rather is required by Ohio law. In March 2022, AEPSC filed a motion to dismiss the Ohio Consumers' Counsel's February 2022 complaint with the FERC on the basis of certain deficiencies including that the complaint fails to request relief that can be granted under FERC regulations because AEPSC is not a public utility nor does it have a transmission rate on file with the FERC.Management believes its financial statements adequately address the impact of the February 2022 complaint. If the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2021 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letters of Credit (Applies to AEP and AEP Texas)

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

AEP has $4 billion and $1 billion revolving credit facilities due in March 2027 and 2024, respectively, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of September 30, 2022, 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 five uncommitted facilities totaling $400 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of September 30, 2022 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 309.9	October 2022 to August 2023
AEP Texas	1.8	July 2023

Guarantees of Equity Method Investees (Applies to AEP)

In 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 September 30, 2022, the maximum potential amount of future payments associated with these guarantees was $120 million, with the last guarantee expiring in December 2037. The non-contingent liability recorded associated with these guarantees was $5 million, with an additional $395 thousand expected credit loss liability for the contingent portion of the guarantees. In accordance with the accounting guidance for guarantees, the initial recognition of the non-contingent liabilities increased AEP's carrying values of the respective equity method investees. 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.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2022, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of September 30, 2022, 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	$ 45.9
AEP Texas	10.9
APCo	6.3
I&M	4.3
OPCo	7.4
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 trusts were capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The trusts own undivided interests in Rockport Plant, Unit 2 and leases equal portions to AEGCo and I&M. In April 2021, AEGCo and I&M executed an agreement to purchase 100% of the interests in the Rockport Plant, Unit 2 effective at the end of the lease term in December 2022.In December 2021, AEGCo and I&M satisfied the necessary regulatory approvals to complete the acquisition.Upon receipt of the regulatory approval, the addition of the lessee forward purchase obligation resulted in the modified lease changing classification from operating to finance for AEGCo and I&M. The future minimum lease payments as of September 30, 2022, inclusive of the purchase obligation, were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2022	$ 174.9	$ 87.4
Total Future Minimum Lease Payments	$ 174.9	$ 87.4

(a) AEP's future minimum lease payments include equal shares from AEGCo and I&M.

The lease modification also created variable interests in the trusts that own the undivided interests in Rockport Plant, Unit 2 for AEGCo and I&M. Neither AEGCo nor I&M are the primary beneficiaries of the trusts because AEGCo nor I&M has the power to direct the most significant activities of the trusts. AEP and I&M's maximum exposure to loss associated with the trust is equal to the total future minimum lease payments, inclusive of the purchase obligation, as shown in the table above.

AEPRO Boat and Barge Leases (Applies to AEP)

In 2015, AEP sold its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party.Certain boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the respective lessors, ensuring future payments under such leases with maturities up to 2027. As of September 30, 2022, the maximum potential amount of future payments required under the guaranteed leases was $36 million. Under the terms of certain of the arrangements, upon the lessors exercising their rights after an event of default by the nonaffiliated party, AEP is entitled to enter into new lease arrangements as a lessee that would have substantially the same terms as the existing leases. Alternatively, for the arrangements with one of the lessors, upon an event of default by the nonaffiliated party and the lessor exercising its rights, payment to the lessor would allow AEP to step into the lessor's rights as well as obtaining title to the assets. Under either situation, AEP would have the ability to utilize the assets in the normal course of barging operations. AEP would also have the right to sell the acquired assets for which it obtained title. As of September 30, 2022, AEP's boat and barge lease guarantee liability was $2 million, of which $1 million was recorded in Other Current Liabilities and $1 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheets.

In February 2020, the nonaffiliated party filed Chapter 11 bankruptcy. The party entered into a restructuring support agreement and has announced it expected to continue their operations as normal. In March 2020, the bankruptcy court approved the party's recapitalization plan. In April 2020, the nonaffiliated party emerged from bankruptcy. Management has determined that it is reasonably possible that enforcement of AEP's liability for future payments under these leases will be exercised within the next twelve months. In such an event, if AEP is unable to sell or incorporate any of the acquired assets into its fleet operations, it could reduce future net income and cash flows and impact financial condition.

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

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

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

NUCLEAR CONTINGENCIES (Applies to AEP and I&M)

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

OPERATIONAL CONTINGENCIES

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

In 2013, the Wilmington Trust Company filed suit 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 sought a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs.

After the litigation proceeded at the district court and appellate court, in April 2021, I&M and AEGCo reached an agreement to acquire 100% of the interests in Rockport Plant, Unit 2 for $116 million from certain financial institutions that own the unit through trusts established by Wilmington Trust, the nonaffiliated owner trustee of the ownership interests in the unit, with closing to occur as of the end of the Rockport Plant, Unit 2 lease in December 2022. The agreement is subject to customary closing conditions and as of the closing will result in a final settlement of, and release of claims in, the lease litigation. As a result, in May 2021, at the parties' request, the district court entered a stipulation and order dismissing the case without prejudice to plaintiffs asserting their claims in a re-filed action or a new action. The required regulatory approvals at the IURC and FERC have been obtained that would allow the closing to occur as of the end of the lease in December 2022. Management believes its financial statements appropriately reflect the resolution of the litigation.

Upon the end of the Rockport Unit 2 lease in December 2022, AEGCo's 50% ownership share of Rockport Unit 2 will be billed 100% to I&M under a FERC-approved unit power agreement. In addition, upon the end of the Rockport Unit 2 lease, I&M's 50% ownership share of Rockport Unit 2 and I&M's purchased power from AEGCo related to Rockport Unit 2 will be a merchant resource for I&M until Rockport Unit 2 is retired. A 2021 IURC order approved a settlement agreement addressing the future use of Rockport Unit 2 as a short-term capacity resource through the June 2023 - May 2024 PJM planning year. I&M has a similar proposal pending before the MPSC in I&M's 2022 Michigan Integrated Resource Plan (IRP) filing. If I&M cannot recover its future investment and expenses related to the merchant share of Rockport Unit 2, it could reduce future net income and cash flows and impact financial condition.

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

Four participants in The American Electric Power System Retirement Plan (the Plan) filed a class action complaint in December 2021 in the U.S District Court for the Southern District of Ohio against AEPSC and the Plan. 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 plaintiffs assert a number of claims on behalf of themselves and the purported class, including 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) AEP failed to provide required notice regarding the changes to the Plan. Among other relief, the Complaint seeks reformation of the Plan to provide additional benefits and the recovery of plan benefits for former employees under such reformed plan. The plaintiffs previously had submitted claims for additional plan benefits to AEP, which were denied. On February 15, 2022, AEPSC and the Plan filed a motion to dismiss the complaint for failure to state a claim. On August 16, 2022, the district court granted the motion to dismiss the complaint without prejudice. The plaintiffs have filed a motion for leave to file an amended complaint. AEP 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 (HB 6)

In 2019, Ohio adopted and implemented HB 6 which benefits OPCo by authorizing rate recovery for certain costs including renewable energy contracts and OVEC's coal-fired generating units. OPCo engaged in lobbying efforts and provided testimony during the legislative process in connection with HB 6. In July 2020, an investigation led by the U.S. Attorney's Office resulted in a federal grand jury indictment of an Ohio legislator and associates in connection with an alleged racketeering conspiracy involving the adoption of HB 6. After AEP learned of the criminal allegations against the Ohio legislator and others relating to HB 6, AEP, with assistance from outside advisors, conducted a review of the circumstances surrounding the passage of the bill. Management does not believe that AEP was involved in any wrongful conduct in connection with the passage of HB 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 amended complaint alleged misrepresentations or omissions by AEP regarding: (a) its alleged participation in or connection to public corruption with respect to the passage of HB 6 and (b) its regulatory, legislative, political contribution, 501(c)(4) organization contribution and lobbying activities in Ohio. The complaint sought monetary damages, among other forms of relief. In December 2021, the district court issued an opinion and order dismissing the securities litigation complaint with prejudice, determining that the complaint failed to plead any actionable misrepresentations or omissions. The plaintiffs did not appeal the ruling.

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. In April 2021, a third AEP shareholder filed a similar derivative action in the U.S. District Court for the Southern District of Ohio and a fourth AEP shareholder filed a similar derivative action in the Supreme Court for the State of New York, Nassau County. These 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 derivative complaints together assert claims for: (a) breach of fiduciary duty, (b) waste of corporate assets, (c) unjust enrichment, (d) breach of duty for insider trading and (e) contribution for violations of sections 10(b) and 21D of the Securities Exchange Act of 1934; and seek monetary damages and changes to AEP's corporate governance and internal policies among other forms of relief. The court entered a scheduling order in the New York state court derivative action staying the case other than with respect to briefing the motion to dismiss. AEP filed its motion to dismiss on April 29, 2022. On September 13, 2022, the New York state court granted the motion to dismiss with prejudice and plaintiffs have filed a notice of appeal with the New York appellate court. The two derivative actions pending in federal district court in Ohio have been consolidated and the plaintiffs in the consolidated action filed an amended complaint. AEP filed a motion to dismiss on May 3, 2022 and briefing on the motion to dismiss has been completed. Discovery remains stayed pending the district court's ruling on the motion to dismiss. The plaintiff in the Ohio state court case advised that they no longer agreed to stay the proceedings, therefore, AEP filed a motion to continue the stays of proceedings on May 20, 2022 and the plaintiff filed an amended complaint on June 2, 2022. On June 15, 2022, the Ohio state court entered an order continuing the stays of that case until the resolution of the consolidated derivative actions pending in Ohio federal district court. The defendants will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

In March 2021, AEP received a litigation demand letter from counsel representing a purported AEP shareholder. The litigation demand letter is directed to the Board of Directors of AEP and contains factual allegations involving HB 6 that are generally consistent with those in the derivative litigation filed in state and federal court. The letter demands, among other things, that the AEP Board undertake an independent investigation into alleged legal violations by directors and officers, and that, following such investigation, AEP commence a civil action for breaches of fiduciary duty and related claims and take appropriate disciplinary action against those individuals who allegedly harmed the company. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect.

In May 2021, AEP received a subpoena from the SEC's Division of Enforcement seeking various documents, including documents relating to the passage of HB 6 and documents relating to AEP's policies and financial processes and controls. In August 2022, AEP received a second subpoena from the SEC seeking various additional documents relating to its ongoing inquiry. AEP is cooperating fully with the SEC's investigation. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this inquiry will have a material impact on financial condition, results of operations or cash flows.

6. ACQUISITIONS, ASSETS AND LIABILITIES HELD FOR SALE, DISPOSITIONS AND IMPAIRMENTS

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

ACQUISITIONS

Dry Lake Solar Project (Generation & Marketing Segment) (Applies to AEP)

In November 2020, AEP signed a Purchase and Sale Agreement with a nonaffiliate to acquire a 75% interest in the entity that owns the 100 MW Dry Lake Solar Project (collectively referred to as Dry Lake) located in southern Nevada for approximately $114 million. In March 2021, AEP closed the transaction and the solar project was placed in-service in May 2021. Approximately $103 million of the purchase price was paid upon closing of the transaction and the remaining $11 million was paid when the project was placed in-service. In accordance with the accounting guidance for "Business Combinations," management determined that the acquisition of Dry Lake represents an asset acquisition. Additionally, and in accordance with the accounting guidance for "Consolidation," management concluded that Dry Lake is a VIE and that AEP is the primary beneficiary based on its power as managing member to direct the activities that most significantly impact Dry Lake's economic performance. As the primary beneficiary of Dry Lake, AEP consolidates Dry Lake into its financial statements. As a result, to account for the initial consolidation of Dry Lake, 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 Dry Lake and recent third-party market transactions for similar solar generation facilities. The nonaffiliated interest in Dry Lake is presented in Noncontrolling Interests on the balance sheets. Subsequent to close of the transaction, the noncontrolling interest made additional asset contributions of $16 million. As of September 30, 2022, AEP recognized approximately $143 million of Property, Plant and Equipment and approximately $34 million of Noncontrolling Interest on the balance sheets.

North Central Wind Energy Facilities (Vertically Integrated Utilities Segment) (Applies to AEP, PSO and SWEPCo)

In 2020, PSO and SWEPCo received regulatory approvals to acquire the NCWF, comprised of three Oklahoma wind facilities totaling 1,484 MWs, on a fixed cost turn-key basis at completion. PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively. In total, the three wind facilities cost approximately $2 billion and consist of Traverse (998 MW), Maverick (287 MW) and Sundance (199 MW). Output from the NCWF serves retail load in PSO's Oklahoma service territory and both retail and FERC wholesale load in SWEPCo's service territories in Arkansas and Louisiana. The Oklahoma and Louisiana portions of the NCWF revenue requirement, net of PTC benefit, are recoverable through authorized riders beginning at commercial operation and until such time as amounts are reflected in base rates. Recovery of the Arkansas portion of the NCWF revenue requirement through base rates was approved by the APSC in May 2022. The NCWF are subject to various regulatory performance requirements. If these performance requirements are not met, PSO and SWEPCo would recognize a regulatory liability to refund retail customers.

In April 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Sundance during its development and construction for $270 million, the first of the three NCWF acquisitions. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the Sundance assets in proportion to their undivided ownership interests. Sundance was placed in-service in April 2021.

In September 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Maverick during its development and construction for $383 million, the second of the three NCWF acquisitions. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the

Maverick assets in proportion to their undivided ownership interests. Maverick was placed in-service in September 2021.

In March 2022, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Traverse during its development and construction for $1.2 billion, the third of the three NCWF acquisitions. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the Traverse assets in proportion to their undivided ownership interests. Traverse was placed in-service in March 2022.

In accordance with the guidance for "Business Combinations," management determined that the acquisitions of the NCWF projects represent asset acquisitions. As of September 30, 2022, PSO and SWEPCo had approximately $894 million and $1.1 billion, of gross Property, Plant and Equipment on the balance sheets, respectively, related to the NCWF projects. On an ongoing basis, management further determined that PSO and SWEPCo should apply the joint plant accounting model to account for their respective undivided interests in the assets, liabilities, revenues and expenses of the NCWF projects.

The respective Purchase and Sale Agreements (PSAs) include interests in numerous land contracts, as originally executed between the nonaffiliated party and the respective owners of the properties as defined in the contracts. These contracts provide for easement and access rights to the land that Sundance, Maverick and Traverse were built upon. The lessee interests in the land contracts were transferred to Sundance, Maverick and Traverse (and subsequently to PSO and SWEPCo) as a part of the closings of the respective PSAs. The current Obligations Under Operating Leases related to the NCWF projects were immaterial as of September 30, 2022 and December 31, 2021 for PSO and SWEPCo. See the table below for the noncurrent Obligations Under Operating Leases for the NCWF projects for PSO and SWEPCo:

	PSO		SWEPCo	
	September 30, 2022	December 31, 2021	September 30, 2022	December 31, 2021
	(in millions)			
Project				
Sundance	$ 12.6	$ 12.6	$ 15.0	$ 15.1
Maverick	18.0	18.0	21.6	21.6
Traverse	39.7	—	47.7	—
Total	$ 70.3	$ 30.6	$ 84.3	$ 36.7

ASSETS AND LIABILITIES HELD FOR SALE

Disposition of KPCo and KTCo (Vertically Integrated Utilities and AEP Transmission Holdco Segments) (Applies to AEP and AEPTCo)

In October 2021, AEP entered into a Stock Purchase Agreement (SPA) to sell KPCo and KTCo to Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corp. (Liberty), for approximately a $2.85 billion enterprise value. In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. AEP has received clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and the Committee on Foreign Investment in the United States. The sale remains subject to FERC approval under Section 203 of the Federal Power Act.

In September 2022, AEP, AEPTCo and Liberty entered into an amendment (Amendment) to the SPA which reduced the purchase price to approximately $2.646 billion and Liberty agreed to waive, upon FERC approval of the sale, the SPA condition precedent to closing requiring the issuance of regulatory orders approving a new proposed Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo. The Amendment also provided that the closing shall not occur prior to January 4, 2023, unless mutually agreed to by AEP and Liberty.

Mitchell Plant Operations and Maintenance Agreement and Ownership Agreement

KPCo and WPCo each own a 50% undivided interest in the 1,560 MW coal-fired Mitchell Plant. As of September 30, 2022, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $576 million.

In November 2021, AEP made filings with the KPSC, WVPSC and FERC seeking approval of a new proposed Mitchell Plant Operations an Maintenance Agreement and Mitchell Plant Ownership Agreement. In February 2022, AEP filed a motion to withdraw its filing with the FERC. The KPSC and WVPSC issued orders addressing AEP's filings in May 2022 and July 2022. Those orders proposed materially different modifications to the Mitchell Plant agreements filed by AEP such that the new agreements could not be executed by the parties. In lieu of new agreements, in July 2022, KPCo and WPCo confirmed with the KPSC and WVPSC, respectively, that they will continue operating under the existing Mitchell Agreemen utilizing the Mitchell Agreement Operating Committee's authority under that agreement to issue appropriate resolutions so the parties can operate in accordance with each state commission's directives related to CCR and ELG investment. In September 2022, pursuant to resolutions under the existing Mitchell Plant agreement, WPCo replaced KPCo as the Operator of Mitchell Plant.

Transfer of Ownership

FERC Proceedings

In December 2021, Liberty, KPCo and KTCo requested FERC approval of the sale under Section 203 of the Federal Power Act. In February 2022, several intervenors in the case filed protests related to whether the sale will negatively impact the wholesale transmission rates of applicants. In April 2022, the FERC issued a deficiency letter stating that the Section 203 application is deficient and that additional information is required to process it. In May 2022, Liberty, KPCo and KTCo supplemented the application and in June 2022, the FERC issued an order formally notifying AEP that it wa exercising its ability to take up to an additional 180 days to act on the application. An order from the FERC is expected in the fourth quarter of 2022.

KPSC Proceedings

In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to conditions contingent upon the closing of the sale, including establishment of regulatory liabilities to subsidize retail customer transmission and distribution expenses, a fuel adjustment clause bill credit, and a three-year Big Sandy decommissioning rider rate holiday during which KPCo's carrying charge is reduced by 50%. As a result of the conditions imposed by KPSC, in the second quarter of 2022, AEP recorded a $69 million loss on the expected sale of the Kentucky Operations in accordance with accounting guidance for Fair Value Measurement.

Further, as a result of the Amendment and the change to the anticipated timing of the completion of the transaction, AEP recorded an additional $194 million pretax loss ($149 million net of tax) on the expected sale of the Kentucky Operations in the third quarter of 2022 in accordance with the accounting guidance for Fair Value Measurement. AEP recorded a $263 million pretax loss ($218 million net of tax) on the expected sale of the Kentucky Operations for the nine months ended September 30, 2022. AEP expects cash proceeds, net of taxes and transaction fees, from the sale of approximately $1.2 billion.

Subject to receipt of FERC authorization under Section 203 of the Federal Power Act, the sale is expected to close in January 2023 with Liberty acquiring the assets and assuming the liabilities of KPCo and KTCo, excluding pension and other post-retirement benefit plan assets and liabilities. AEP expects to provide customary transition services to Liberty for a period of time after closing of the transaction. AEP plans to use the proceeds from the sale to fund its continued investment in regulated businesses, including transmission and regulated renewables projects. If additional reductions in the fair value of the Kentucky Operations occur, it would reduce future net income and cash flows.

The Income Before Income Tax Expense (Benefit) of KPCo and KTCo were not material to AEP and AEPTCo on their respective statements of income for the three and nine months ended September 30, 2022 and 2021.

The major classes of KPCo and KTCo's assets and liabilities presented in Assets Held for Sale and Liabilities Held for Sale on the balance sheets of AEP and AEPTCo are shown in the table below:

	AEP		AEPTCo	
	September 30, 2022	December 31, 2021	September 30, 2022	December 31, 2021
	(in millions)			
ASSETS				
Accounts Receivable and Accrued Unbilled Revenues	$ 77.8	$ 33.2	$ 1.7	$ 1.5
Fuel, Materials and Supplies	36.7	30.6	—	—
Property, Plant and Equipment, Net	2,387.4	2,302.7	167.0	165.3
Regulatory Assets	508.6	484.7	—	—
Other Classes of Assets that are not Major	38.1	68.5	5.0	1.1
Total Major Classes of Assets Held for Sale	3,048.6	2,919.7	173.7	167.9
Loss on the Expected Sale of Kentucky Operations (net of $45 million of Income Taxes)	(218.0)	—	—	—
Assets Held for Sale	$ 2,830.6	$ 2,919.7	$ 173.7	$ 167.9
LIABILITIES				
Accounts Payable	$ 62.4	$ 53.4	$ 0.7	$ 1.1
Long-term Debt Due Within One Year	215.0	200.0	—	—
Customer Deposits	38.0	32.4	—	—
Deferred Income Taxes	497.8	441.6	16.4	15.4
Long-term Debt	963.4	903.1	—	—
Regulatory Liabilities and Deferred Investment Tax Credits	138.1	148.1	8.0	7.6
Other Classes of Liabilities that are not Major	77.3	102.3	2.5	3.5
Liabilities Held for Sale	$ 1,992.0	$ 1,880.9	$ 27.6	$ 27.6

DISPOSITIONS

Disposition of Cardinal Plant (Generation & Marketing Segment) (Applies to AEP)

In March 2022, AGR entered into an Asset Purchase agreement with a nonaffiliated electric cooperative to sell Cardinal Plant, Unit 1, a competitive generation asset totaling 595 MWs. The FERC approved the sale in May 2022 and the sale closed in the third quarter of 2022.The proceeds from the sale were not material. Concurrent with the closing of the sale, AGR executed a PPA with the nonaffiliated electric cooperative for rights to Unit 1's power and capacity through 2028. AGR also retained certain obligations related to environmental remediation.

Subsequent to the closing of the sale, AGR continues to recognize Cardinal Plant, Unit 1 on its balance sheet due to continuing involvement through the PPA. As of September 30, 2022, the net book value of Cardinal Plant, Unit 1 was not material.

Disposition of Mineral Rights (Generation & Marketing Segment) (Applies to AEP)

In June 2022, AEP closed on the sale of certain mineral rights to a nonaffiliated third-party and received $120 million of proceeds. The sale resulted in a pretax gain of $116 million in the second quarter of 2022.

IMPAIRMENTS

Flat Ridge 2 Wind LLC (Generation & Marketing Segment) (Applies to AEP)

In April 2019, AEP acquired Sempra Renewables LLC and its ownership interests in 724 MWs of wind generation and battery assets. The acquisition included a 50% ownership interest in five non-consolidated joint ventures, including Flat Ridge 2 Wind LLC (Flat Ridge 2), and two tax equity partnerships. The five non-consolidated joint ventures are jointly owned and operated by BP Wind Energy. Flat Ridge 2 sells electricity to three counterparties through long-term PPAs.

Regarding AEP's investment in Flat Ridge 2, in June 2022, as a result of deteriorating financial performance, sale negotiations and AEP's ongoing evaluation and ultimate decision to exit the investment in the near term, AEP determined a decline in the fair value of AEP's investment in Flat Ridge 2 was other than temporary and recorded a pretax other than temporary impairment charge of $186 million in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's Statement of Income. In the third quarter of 2022, in accordance with the accounting guidance for "Investments - Equity Method and Joint Ventures", AEP recorded an additional $2 million pretax other than temporary impairment charge in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's Statement of Income. AEP has recorded a $188 million other than temporary impairment in its investment in Flat Ridge 2 for the nine months ended September 30, 2022 in Equity Earnings (Losses) of Unconsolidated Subsidiaries on AEP's Statement of Income. AEP's determination of fair value utilized the accounting guidance for Fair Value Measurement market approach to valuation and was based on Level 2 pricing information from a third-party market participant. In September 2022, AEP signed a Purchase and Sale Agreement with a nonaffiliate for AEP's interest in Flat Ridge 2, subject to FERC approval. Management expects the transaction to close in the fourth quarter of 2022 and have an immaterial impact on the financial statements. The carrying value of AEP's investment in Flat Ridge 2 was not material to AEP as of September 30, 2022.

7. BENEFIT PLANS

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

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

Components of Net Periodic Benefit Cost

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

AEP

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 30.7	$ 32.3	$ 1.8	$ 2.4
Interest Cost	37.1	34.3	7.3	7.7
Expected Return on Plan Assets	(63.4)	(57.4)	(27.5)	(22.8)
Amortization of Prior Service Credit	—	—	(17.9)	(17.8)
Amortization of Net Actuarial Loss	15.8	25.3	—	—
Net Periodic Benefit Cost (Credit)	$ 20.2	$ 34.5	$ (36.3)	$ (30.5)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 92.3	$ 96.9	$ 5.5	$ 7.2
Interest Cost	111.2	102.9	21.9	22.9
Expected Return on Plan Assets	(190.1)	(172.3)	(82.5)	(68.4)
Amortization of Prior Service Credit	—	—	(53.6)	(53.2)
Amortization of Net Actuarial Loss	47.3	76.1	—	—
Net Periodic Benefit Cost (Credit)	$ 60.7	$ 103.6	$ (108.7)	$ (91.5)

AEP Texas

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 2.8	$ 3.0	$ 0.1	$ 0.2
Interest Cost	3.1	2.8	0.6	0.6
Expected Return on Plan Assets	(5.3)	(4.9)	(2.3)	(1.9)
Amortization of Prior Service Credit	—	—	(1.5)	(1.5)
Amortization of Net Actuarial Loss	1.2	2.1	—	—
Net Periodic Benefit Cost (Credit)	$ 1.8	$ 3.0	$ (3.1)	$ (2.6)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 8.4	$ 8.9	$ 0.3	$ 0.5
Interest Cost	9.1	8.4	1.7	1.8
Expected Return on Plan Assets	(15.8)	(14.6)	(6.8)	(5.6)
Amortization of Prior Service Credit	—	—	(4.5)	(4.5)
Amortization of Net Actuarial Loss	3.8	6.2	—	—
Net Periodic Benefit Cost (Credit)	$ 5.5	$ 8.9	$ (9.3)	$ (7.8)

APCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 2.9	$ 3.0	$ 0.2	$ 0.3
Interest Cost	4.3	4.1	1.2	1.3
Expected Return on Plan Assets	(8.1)	(7.3)	(4.1)	(3.4)
Amortization of Prior Service Credit	—	—	(2.6)	(2.6)
Amortization of Net Actuarial Loss	1.9	3.0	—	—
Net Periodic Benefit Cost (Credit)	$ 1.0	$ 2.8	$ (5.3)	$ (4.4)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 8.6	$ 8.9	$ 0.6	$ 0.8
Interest Cost	13.1	12.3	3.5	3.7
Expected Return on Plan Assets	(24.3)	(21.8)	(12.2)	(10.1)
Amortization of Prior Service Credit	—	—	(7.8)	(7.8)
Amortization of Net Actuarial Loss	5.5	9.0	—	—
Net Periodic Benefit Cost (Credit)	$ 2.9	$ 8.4	$ (15.9)	$ (13.4)

I&M

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 4.0	$ 4.4	$ 0.2	$ 0.4
Interest Cost	4.3	4.0	0.8	0.8
Expected Return on Plan Assets	(8.1)	(7.2)	(3.3)	(2.7)
Amortization of Prior Service Credit	—	—	(2.4)	(2.5)
Amortization of Net Actuarial Loss	1.8	2.9	—	—
Net Periodic Benefit Cost (Credit)	$ 2.0	$ 4.1	$ (4.7)	$ (4.0)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 12.1	$ 13.1	$ 0.7	$ 1.0
Interest Cost	12.7	12.1	2.5	2.6
Expected Return on Plan Assets	(24.2)	(21.6)	(10.2)	(8.3)
Amortization of Prior Service Credit	—	—	(7.3)	(7.3)
Amortization of Net Actuarial Loss	5.3	8.8	—	—
Net Periodic Benefit Cost (Credit)	$ 5.9	$ 12.4	$ (14.3)	$ (12.0)

OPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 2.8	$ 2.9	$ 0.2	$ 0.2
Interest Cost	3.4	3.1	0.7	0.7
Expected Return on Plan Assets	(6.2)	(5.7)	(3.0)	(2.4)
Amortization of Prior Service Credit	—	—	(1.8)	(1.7)
Amortization of Net Actuarial Loss	1.3	2.3	—	—
Net Periodic Benefit Cost (Credit)	$ 1.3	$ 2.6	$ (3.9)	$ (3.2)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 8.4	$ 8.6	$ 0.5	$ 0.6
Interest Cost	10.0	9.3	2.2	2.3
Expected Return on Plan Assets	(18.6)	(16.8)	(8.9)	(7.3)
Amortization of Prior Service Credit	—	—	(5.4)	(5.3)
Amortization of Net Actuarial Loss	4.1	6.8	—	—
Net Periodic Benefit Cost (Credit)	$ 3.9	$ 7.9	$ (11.6)	$ (9.7)

PSO

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 1.8	$ 2.0	$ 0.2	$ 0.1
Interest Cost	1.8	1.7	0.4	0.4
Expected Return on Plan Assets	(3.3)	(3.0)	(1.6)	(1.3)
Amortization of Prior Service Credit	—	—	(1.1)	(1.1)
Amortization of Net Actuarial Loss	0.7	1.2	—	—
Net Periodic Benefit Cost (Credit)	$ 1.0	$ 1.9	$ (2.1)	$ (1.9)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 5.5	$ 6.0	$ 0.4	$ 0.4
Interest Cost	5.3	5.0	1.1	1.2
Expected Return on Plan Assets	(10.1)	(9.2)	(4.6)	(3.8)
Amortization of Prior Service Credit	—	—	(3.3)	(3.3)
Amortization of Net Actuarial Loss	2.2	3.7	—	—
Net Periodic Benefit Cost (Credit)	$ 2.9	$ 5.5	$ (6.4)	$ (5.5)

SWEPCo

	Pension Plans		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 2.7	$ 2.7	$ 0.1	$ 0.3
Interest Cost	2.2	2.2	0.5	0.4
Expected Return on Plan Assets	(3.6)	(3.3)	(1.8)	(1.5)
Amortization of Prior Service Credit	—	—	(1.4)	(1.4)
Amortization of Net Actuarial Loss	0.9	1.5	—	—
Net Periodic Benefit Cost (Credit)	$ 2.2	$ 3.1	$ (2.6)	$ (2.2)

	Pension Plans		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Service Cost	$ 8.0	$ 8.4	$ 0.4	$ 0.6
Interest Cost	6.8	6.4	1.4	1.4
Expected Return on Plan Assets	(10.9)	(10.1)	(5.5)	(4.5)
Amortization of Prior Service Credit	—	—	(4.0)	(4.0)
Amortization of Net Actuarial Loss	2.8	4.6	—	—
Net Periodic Benefit Cost (Credit)	$ 6.7	$ 9.3	$ (7.7)	$ (6.5)

8. BUSINESS SEGMENTS

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

AEP's Reportable Segments

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

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

Vertically Integrated Utilities

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

Transmission and Distribution Utilities

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

AEP Transmission Holdco

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

Generation & Marketing

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

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

The tables below represent AEP's reportable segment income statement information for the three and nine months ended September 30, 2022 and 2021 and reportable segment balance sheet information as of September 30, 2022 and December 31, 2021.

	Three Months Ended September 30, 2022						
	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	$ 3,174.6	$ 1,525.5	$ 81.9	$ 733.1	$ 11.0	$ —	$ 5,526.1
Other Operating Segments	51.7	4.7	349.0	2.3	17.3	(425.0)	—
Total Revenues	$ 3,226.3	$ 1,530.2	$ 430.9	$ 735.4	$ 28.3	$ (425.0)	$ 5,526.1
Net Income (Loss)	$ 476.9	$ 165.5	$ 171.4	$ 96.2	$ (226.7)	$ —	$ 683.3

	Three Months Ended September 30, 2021						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 2,716.8	$ 1,195.0	$ 90.3	$ 617.4	$ 3.5	$ —	$ 4,623.0
Other Operating Segments	42.5	5.3	301.3	3.7	23.2	(376.0)	—
Total Revenues	$ 2,759.3	$ 1,200.3	$ 391.6	$ 621.1	$ 26.7	$ (376.0)	$ 4,623.0
Net Income (Loss)	$ 438.7	$ 155.9	$ 167.9	$ 99.5	$ (65.1)	$ —	$ 796.9

	Nine Months Ended September 30, 2022						
	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	$ 8,416.4	$ 4,064.5	$ 244.4	$ 1,997.0	$ 36.1	$ —	$ 14,758.4
Other Operating Segments	145.8	14.1	976.7	17.3	36.6	(1,190.5)	—
Total Revenues	$ 8,562.2	$ 4,078.6	$ 1,221.1	$ 2,014.3	$ 72.7	$ (1,190.5)	$ 14,758.4
Net Income (Loss)	$ 1,079.4	$ 483.1	$ 487.8	$ 278.1	$ (406.2)	$ —	$ 1,922.2

	Nine Months Ended September 30, 2021						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 7,445.9	$ 3,366.9	$ 264.6	$ 1,641.6	$ 11.6	$ —	$ 12,730.6
Other Operating Segments	111.3	24.9	882.2	50.3	43.5	(1,112.2)	—
Total Revenues	$ 7,557.2	$ 3,391.8	$ 1,146.8	$ 1,691.9	$ 55.1	$ (1,112.2)	$ 12,730.6
Net Income (Loss)	$ 938.9	$ 424.0	$ 510.7	$ 184.2	$ (108.3)	$ —	$ 1,949.5

	September 30, 2022						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Assets (d)	$ 49,056.9	$ 22,139.7	$ 14,708.9	$ 5,376.3	$ 6,278.3 (b)	$ (6,310.7) (c)	$ 91,249.4

	December 31, 2021						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Assets (d)	$ 46,974.2	$ 21,120.2	$ 13,873.3	$ 4,263.6	$ 5,846.5 (b)	$ (4,409.1) (c)	$ 87,668.7

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense and other nonallocated costs.
(b) Includes 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) Amount includes Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

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

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business for APCo, I&M, PSO and SWEPCo, and an integrated electricity transmission and distribution business for AEP Texas and OPCo. Other activities ar 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 utilitiesThe seven State Transcos have been identified as operating segments of AEPTCo under the accounting guidance for "Segment Reporting."The State Transcos business consists of developing, constructing and operating transmission facilities at the request of the RTOs in which they operate and in replacing and upgrading facilities, assets and components of the existing AEP transmission system as needed to maintain reliability standards and provide service to AEP's wholesale and retail customers. The State Transcos are regulated for rate-making purposes exclusively by the FERC and earn revenues through tariff rates charged for the use of their electric transmission systems.

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

The tables below present AEPTCo's reportable segment income statement information for the three and nine months ended September 30, 2022 and 2021 and reportable segment balance sheet information as of September 30, 2022 and December 31, 2021.

	Three Months Ended September 30, 2022			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 87.2	$ —	$ —	$ 87.2
Sales to AEP Affiliates	331.3	—	—	331.3
Total Revenues	$ 418.5	$ —	$ —	$ 418.5
Net Income	$ 152.6	$ 0.1 (a)	$ —	$ 152.7

	Three Months Ended September 30, 2021			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 79.2	$ —	$ —	$ 79.2
Sales to AEP Affiliates	297.6	—	—	297.6
Other Revenues	0.2	—	—	0.2
Total Revenues	$ 377.0	$ —	$ —	$ 377.0
Net Income	$ 145.3	$ 0.1 (a)	$ —	$ 145.4

	Nine Months Ended September 30, 2022			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 249.5	$ —	$ —	$ 249.5
Sales to AEP Affiliates	933.8	—	—	933.8
Total Revenues	$ 1,183.3	$ —	$ —	$ 1,183.3
Net Income	$ 426.4	$ 0.2 (a)	$ —	$ 426.6

	Nine Months Ended September 30, 2021			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 239.3	$ —	$ —	$ 239.3
Sales to AEP Affiliates	864.6	—	—	864.6
Other Revenues	0.3	—	—	0.3
Total Revenues	$ 1,104.2	$ —	$ —	$ 1,104.2
Net Income	$ 445.5	$ 0.2 (a)	$ —	$ 445.7

	September 30, 2022			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets (d)	$ 13,359.9	$ 4,972.4 (b)	$ (5,013.1) (c)	$ 13,319.2

	December 31, 2021			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets (d)	$ 12,564.3	$ 4,389.5 (b)	$ (4,429.4) (c)	$ 12,524.4

(a) Includes the elimination of AEPTCo Parent's equity earnings in the State Transcos.
(b) Includes the elimination of AEPTCo Parent's investments in State Transcos.
(c) Primarily relates to the elimination of Notes Receivable from the State Transcos.
(d) Amount includes Assets Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

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

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

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Notional Volume of Derivative Instruments
September 30, 2022

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	260.6	—	29.0	6.2	2.6	5.7	4.3
Natural Gas	MMBtus	80.3	—	—	—	—	—	1.8
Heating Oil and Gasoline	Gallons	6.4	1.7	0.9	0.6	1.3	0.7	0.9
Interest Rate	USD	$ 99.9	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 1,150.0	$ —	$ —	$ —	$ —	$ —	$ —

December 31, 2021

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	287.9	—	33.1	13.6	2.7	11.9	3.4
Natural Gas	MMBtus	34.1	—	—	—	—	1.3	5.1
Heating Oil and Gasoline	Gallons	7.4	1.9	1.1	0.7	1.5	0.8	1.0
Interest Rate	USD	$ 116.5	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 950.0	$ —	$ —	$ —	$ —	$ —	$ —

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 $847 million and $263 million as of September 30, 2022 and December 31, 2021, respectively. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $0 and $3 million as of September 30, 2022 and December 31, 2021, respectively. The netted cash collateral from third-parties against short-term and long-term risk management assets and netted cash collateral paid to third-parties against short-term and long-term risk management liabilities were immaterial for the Registrant Subsidiaries as of September 30, 2022 and December 31, 2021.

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets. Unless shown as a separate line on the balance sheets due to materiality, Current Risk Management Assets are included in Prepayments and Other Current Assets, Long-term Risk Management Assets are included in Deferred Charges and Other Noncurrent Assets, Current Risk Management Liabilities are included in Other Current Liabilities and Long-term Risk Management Liabilities are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

AEP

	September 30, 2022					
	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 (d)	$ 1,482.1	$ 411.1	$ 8.8	$ 1,902.0	$ (1,331.8)	$ 570.2
Long-term Risk Management Assets	686.6	177.4	—	864.0	(598.2)	265.8
Total Assets	2,168.7	588.5	8.8	2,766.0	(1,930.0)	836.0
Current Risk Management Liabilities (e)	1,005.7	10.9	21.3	1,037.9	(850.6)	187.3
Long-term Risk Management Liabilities	501.6	4.9	114.1	620.6	(232.4)	388.2
Total Liabilities	1,507.3	15.8	135.4	1,658.5	(1,083.0)	575.5
Total MTM Derivative Contract Net Assets (Liabilities) (f)	$ 661.4	$ 572.7	$ (126.6)	$ 1,107.5	$ (847.0)	$ 260.5

	December 31, 2021					
	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 (d)	$ 513.4	$ 176.0	$ 1.2	$ 690.6	$ (496.2)	$ 194.4
Long-term Risk Management Assets	370.5	89.1	—	459.6	(192.6)	267.0
Total Assets	883.9	265.1	1.2	1,150.2	(688.8)	461.4
Current Risk Management Liabilities (e)	395.7	40.9	—	436.6	(361.2)	75.4
Long-term Risk Management Liabilities	243.9	16.7	38.1	298.7	(68.4)	230.3
Total Liabilities	639.6	57.6	38.1	735.3	(429.6)	305.7
Total MTM Derivative Contract Net Assets (Liabilities)	$ 244.3	$ 207.5	$ (36.9)	$ 414.9	$ (259.2)	$ 155.7

AEP Texas

Balance Sheet Location	September 30, 2022 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	$ 0.1	$ 0.1	$ 0.2
Long-term Risk Management Assets	(0.1)	0.2	0.1
Total Assets	—	0.3	0.3
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	0.1	0.1
Total Liabilities	—	0.1	0.1
Total MTM Derivative Contract Net Assets	$ —	$ 0.2	$ 0.2

Balance Sheet Location	December 31, 2021 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.6	$ (0.6)	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	0.6	(0.6)	—
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ 0.6	$ (0.6)	$ —

APCo

Balance Sheet Location	September 30, 2022 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	$ 106.8	$ —	$ 106.8
Long-term Risk Management Assets	0.7	(0.6)	0.1
Total Assets	107.5	(0.6)	106.9
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	0.7	(0.7)	—
Total Liabilities	0.7	(0.7)	—
Total MTM Derivative Contract Net Assets (f)	$ 106.8	$ 0.1	$ 106.9

Balance Sheet Location	December 31, 2021 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	$ 47.5	$ (5.5)	$ 42.0
Long-term Risk Management Assets	0.2	(0.2)	—
Total Assets	47.7	(5.7)	42.0
Current Risk Management Liabilities	7.2	(6.4)	0.8
Long-term Risk Management Liabilities	0.2	(0.2)	—
Total Liabilities	7.4	(6.6)	0.8
Total MTM Derivative Contract Net Assets	$ 40.3	$ 0.9	$ 41.2

I&M

Balance Sheet Location	September 30, 2022 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	$ 12.3	$ (0.9)	$ 11.4
Long-term Risk Management Assets	0.6	(0.4)	0.2
Total Assets	12.9	(1.3)	11.6
Current Risk Management Liabilities	0.9	(0.9)	—
Long-term Risk Management Liabilities	0.5	(0.5)	—
Total Liabilities	1.4	(1.4)	—
Total MTM Derivative Contract Net Assets (f)	$ 11.5	$ 0.1	$ 11.6

Balance Sheet Location	December 31, 2021 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	$ 11.1	$ (7.8)	$ 3.3
Long-term Risk Management Assets	0.2	(0.2)	—
Total Assets	11.3	(8.0)	3.3
Current Risk Management Liabilities	14.8	(9.8)	5.0
Long-term Risk Management Liabilities	0.2	(0.2)	—
Total Liabilities	15.0	(10.0)	5.0
Total MTM Derivative Contract Net Assets (Liabilities)	$ (3.7)	$ 2.0	$ (1.7)

OPCo

Balance Sheet Location	September 30, 2022 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	$ 2.0	$ 0.1	$ 2.1
Long-term Risk Management Assets	(0.1)	0.1	—
Total Assets	1.9	0.2	2.1
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	45.1	—	45.1
Total Liabilities	45.1	—	45.1
Total MTM Derivative Contract Net Assets (Liabilities) (f)	$ (43.2)	$ 0.2	$ (43.0)

Balance Sheet Location	December 31, 2021 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	$ 0.5	$ (0.5)	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	0.5	(0.5)	—
Current Risk Management Liabilities	6.7	—	6.7
Long-term Risk Management Liabilities	85.8	—	85.8
Total Liabilities	92.5	—	92.5
Total MTM Derivative Contract Net Liabilities	$ (92.0)	$ (0.5)	$ (92.5)

PSO

Balance Sheet Location	September 30, 2022 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	$ 44.4	$ 0.1	$ 44.5
Long-term Risk Management Assets	—	—	—
Total Assets	44.4	0.1	44.5
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets (f)	$ 44.4	$ 0.1	$ 44.5

Balance Sheet Location	December 31, 2021 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	$ 12.4	$ (0.3)	$ 12.1
Long-term Risk Management Assets	—	—	—
Total Assets	12.4	(0.3)	12.1
Current Risk Management Liabilities	3.7	—	3.7
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	3.7	—	3.7
Total MTM Derivative Contract Net Assets (Liabilities)	$ 8.7	$ (0.3)	$ 8.4

SWEPCo

Balance Sheet Location	September 30, 2022 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	$ 37.2	$ (0.8)	$ 36.4
Long-term Risk Management Assets	—	0.1	0.1
Total Assets	37.2	(0.7)	36.5
Current Risk Management Liabilities	0.8	(0.8)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.8	(0.8)	—
Total MTM Derivative Contract Net Assets (f)	$ 36.4	$ 0.1	$ 36.5

Balance Sheet Location	December 31, 2021 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 10.1	$ (0.3)	$ 9.8
Long-term Risk Management Assets	1.1	—	1.1
Total Assets	11.2	(0.3)	10.9
Current Risk Management Liabilities	2.1	—	2.1
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	2.1	—	2.1
Total MTM Derivative Contract Net Assets (Liabilities)	$ 9.1	$ (0.3)	$ 8.8

(a) Derivative instruments within these categories are disclosed as 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.
(d) Amount excludes Risk Management Assets of $14.4 million and $6 million as of September 30, 2022 and December 31, 2021, respectively, classified as Assets Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.
(e) Amount excludes Risk Management Liabilities of $0 and $0.1 million as of September 30, 2022 and December 31, 2021, respectively, classified as Liabilities Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.
(f) Increase in amounts as of September 30, 2022 are primarily due to increases in commodity prices for power and natural gas and an increase in value of FTRs.

The tables below present the Registrants' amount of gain (loss) recognized on risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Three Months Ended September 30, 2022						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ 2.1	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	116.7	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.3	—	—	—	—
Other Revenues - Nonaffiliated	—	—	—	1.9	—	—	—
Purchased Electricity for Resale	0.9	—	0.9	0.1	—	—	—
Other Operation	1.4	0.4	0.1	0.1	0.2	0.2	0.2
Maintenance	2.0	0.5	0.2	0.2	0.4	0.2	0.3
Regulatory Assets (a)	4.3	—	—	0.1	4.1	—	0.1
Regulatory Liabilities (a)	103.2	(1.5)	59.7	3.8	0.9	19.7	7.0
Total Gain (Loss) on Risk Management Contracts (b)	$ 230.6	$ (0.6)	$ 61.2	$ 6.2	$ 5.6	$ 20.1	$ 7.6

Location of Gain (Loss)	Three Months Ended September 30, 2021						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ (0.9)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	128.8	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.9)	—	—	—	—
Purchased Electricity for Resale	0.2	—	0.1	—	—	—	—
Other Operation	0.9	0.3	0.1	0.1	0.1	0.1	0.2
Maintenance	1.1	0.2	0.2	0.1	0.2	0.1	0.1
Regulatory Assets (a)	(7.2)	—	(2.9)	(16.9)	14.9	—	0.1
Regulatory Liabilities (a)	46.5	(0.1)	14.2	1.7	0.8	14.0	12.7
Total Gain (Loss) on Risk Management Contracts	$ 169.4	$ 0.4	$ 10.8	$ (15.0)	$ 16.0	$ 14.2	$ 13.1

Location of Gain (Loss)	Nine Months Ended September 30, 2022 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 2.2	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	390.0	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.4	(0.1)	—	—	—
Other Revenues - Nonaffiliated	—	—	—	1.9	—	—	—
Purchased Electricity for Resale	3.3	—	3.0	0.1	—	0.1	—
Other Operation	3.7	1.1	0.3	0.4	0.6	0.5	0.6
Maintenance	5.2	1.4	0.7	0.5	0.9	0.6	0.8
Regulatory Assets (a)	49.3	0.1	—	(1.2)	49.0	3.6	(2.1)
Regulatory Liabilities (a)	250.1	(0.6)	79.9	7.0	2.5	71.4	64.8
Total Gain on Risk Management Contracts (b)	$ 703.8	$ 2.0	$ 84.3	$ 8.6	$ 53.0	$ 76.2	$ 64.1

Location of Gain (Loss)	Nine Months Ended September 30, 2021 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ (0.6)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	144.9	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.6)	—	—	—	—
Purchased Electricity for Resale	1.2	—	1.0	0.1	—	—	—
Other Operation	1.9	0.6	0.2	0.2	0.3	0.2	0.3
Maintenance	2.4	0.6	0.4	0.2	0.4	0.2	0.3
Regulatory Assets (a)	(7.9)	—	(2.9)	(22.9)	20.3	—	1.4
Regulatory Liabilities (a)	123.6	0.5	28.9	1.9	5.9	40.2	38.5
Total Gain (Loss) on Risk Management Contracts	$ 265.5	$ 1.7	$ 27.0	$ (20.5)	$ 26.9	$ 40.6	$ 40.5

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.
(b) Increase in amounts for the three and nine months ended September 30, 2022 are primarily due to increases in commodity prices for power and natural gas and an increase in value of FTRs.

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 line item on the statements of income as that of the associated risk being hedged. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies (Applies to AEP)

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

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

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

	Carrying Amount of the Hedged Liabilities		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Liabilities	
	September 30, 2022	December 31, 2021	September 30, 2022	December 31, 2021
	(in millions)			
Long-term Debt (a) (b)	$ (849.1)	$ (952.3)	$ 95.7	$ (8.5)

(a) Amounts included on the Balance Sheet within Current and Noncurrent Liabilities line items Long-term Debt Due within One Year and Long-term Debt, respectively.
(b) Amounts include $(40) million and $(46) million as of September 30, 2022 and December 31, 2021, respectively, for the fair value hedge adjustment of hedged debt obligations for which hedge accounting has been discontinued.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Gain (Loss) on Interest Rate Contracts:				
Fair Value Hedging Instruments (a)	$ (36.0)	$ (0.1)	$ (98.4)	$ (23.8)
Fair Value Portion of Long-term Debt (a)	36.0	0.1	98.4	23.8

(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 statements 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 (Applies to AEP, AEP Texas, APCo, I&M and SWEPCo)

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

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2022 and 2021, AEP applied cash flow hedging to outstanding power derivatives and the Registrant Subsidiaries did not.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2022, AEP applied cash flow hedging to outstanding interest rate derivatives and the Registrant Subsidiaries did not. During the three months ended September 30, 2021, AEP applied cash flow hedging to outstanding interest rate derivatives and the Registrant Subsidiaries did not. During the nine months ended September 30, 2021, AEP and APCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

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

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

Impact of Cash Flow Hedges on AEP's Balance Sheets

	September 30, 2022		December 31, 2021	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ 452.1	$ (2.6)	$ 163.7	$ (21.3)
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	316.2	(1.5)	106.7	(3.3)

As of September 30, 2022 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 102 months and 99 months for commodity and interest rate hedges, respectively.

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

	September 30, 2022		December 31, 2021	
	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	$ (0.5)	$ (0.4)	$ (1.3)	$ (1.1)
APCo	6.9	0.8	7.5	0.8
I&M	(5.5)	(1.0)	(6.7)	(1.6)
SWEPCo	1.2	0.2	1.2	0.1

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

Credit Risk

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

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

Credit-Risk-Related Contingent Features

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. AEP had derivative contracts with collateral triggering events in a net liability position with a total exposure of $10 million and $9 million as of September 30, 2022 and December 31, 2021, respectively. The Registrant Subsidiaries had no derivative contracts with collateral triggering events in a net liability position as of September 30, 2022 and December 31, 2021.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by the Registrants under any of their outstanding debt of at least $50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. AEP had derivative contracts with cross-acceleration provisions in a net liability position of $135 million and $40 million as of September 30, 2022 and December 31, 2021, respectively. There was no cash collateral posted as of September 30, 2022 and December 31, 2021, respectively. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required. The Registrant Subsidiaries had no derivative contracts with cross-acceleration provisions outstanding as of September 30, 2022 and December 31, 2021.

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. AEP had derivative liabilities subject to cross-default provisions in a net liability position of $260 million and $76 million as of September 30, 2022 and December 31, 2021, respectively, after considering contractual netting arrangements. Cash collateral posted as of September 30, 2022 and December 31, 2021 was not material. If a cross-default provision would have been triggered, settlement at fair value would have been required. The Registrant Subsidiaries' derivative contracts with cross-default provisions outstanding as of September 30, 2022 and December 31, 2021 were not material.

10. FAIR VALUE MEASUREMENTS

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

Fair Value Hierarchy and Valuation Techniques

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

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

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

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

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

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

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

	September 30, 2022		December 31, 2021	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in millions)			
AEP (a)(b)(c)	$ 35,050.1	$ 30,352.7	$ 33,454.5	$ 37,564.7
AEP Texas	5,693.9	4,889.7	5,180.8	5,663.8
AEPTCo	4,886.6	3,926.3	4,343.9	4,968.2
APCo	5,509.8	4,994.1	4,938.9	6,037.1
I&M	3,206.7	2,846.2	3,195.0	3,748.0
OPCo	2,969.9	2,442.0	2,968.5	3,437.5
PSO	1,913.6	1,616.9	1,913.5	2,163.7
SWEPCo	3,392.4	2,797.3	3,395.2	3,792.9

(a) The fair value amounts include debt related to AEP's Equity Units and had a fair value of $842 million and $1.7 billion as of September 30, 2022 and December 31, 2021, respectively. See "Equity Units" section of Note 12 for additional information.
(b) The book value amounts exclude Long-term Debt of $1.2 billion and $1.1 billion as of September 30, 2022 and December 31, 2021, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.
(c) The fair value amounts exclude Long-term Debt of $1.1 billion and $1.2 billion as of September 30, 2022 and December 31, 2021, respectively, related to KPCo. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

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

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS.

The following is a summary of Other Temporary Investments and Restricted Cash:

	September 30, 2022			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash (a)	$ 55.1	$ —	$ —	$ 55.1
Other Cash Deposits	18.1	—	—	18.1
Fixed Income Securities – Mutual Funds (b)	155.1	—	(9.7)	145.4
Equity Securities – Mutual Funds	20.4	18.6	(0.3)	38.7
Total Other Temporary Investments and Restricted Cash	$ 248.7	$ 18.6	$ (10.0)	$ 257.3

Other Temporary Investments and Restricted Cash	December 31, 2021 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$ 48.0	$ —	$ —	$ 48.0
Other Cash Deposits	10.0	—	—	10.0
Fixed Income Securities – Mutual Funds (b)	154.3	0.5	—	154.8
Equity Securities – Mutual Funds	19.7	35.9	—	55.6
Total Other Temporary Investments and Restricted Cash	$ 232.0	$ 36.4	$ —	$ 268.4

(a) Primarily represents amounts held for the repayment of debt.
(b) Primarily short and intermediate maturities which may be sold and do not contain maturity dates.

The following table provides the activity for fixed income and equity securities within Other Temporary Investments:

	Three Months Ended September 30, 2022	2021	Nine Months Ended September 30, 2022	2021
	(in millions)			
Proceeds from Investment Sales	$ —	$ 6.0	$ 15.0	$ 15.1
Purchases of Investments	11.8	12.9	13.4	26.0
Gross Realized Gains on Investment Sales	—	2.4	3.6	3.6
Gross Realized Losses on Investment Sales	—	—	0.5	—

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

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

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

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by 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.

The following is a summary of nuclear trust fund investments:

	September 30, 2022			December 31, 2021		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 20.8	$ —	$ —	$ 84.7	$ —	$ —
Fixed Income Securities:						
United States Government	1,115.2	(26.2)	(39.8)	1,156.4	66.3	(7.9)
Corporate Debt	60.9	(7.7)	(1.2)	76.7	6.7	(2.1)
State and Local Government	7.0	—	(0.1)	7.3	0.4	(0.1)
Subtotal Fixed Income Securities	1,183.1	(33.9)	(41.1)	1,240.4	73.4	(10.1)
Equity Securities - Domestic (a)	1,926.6	1,279.1	—	2,541.9	1,901.3	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 3,130.5	$ 1,245.2	$ (41.1)	$ 3,867.0	$ 1,974.7	$ (10.1)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $1.3 billion and $1.9 billion and unrealized losses of $14 million and $4 million as of September 30, 2022 and December 31, 2021, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(in millions)			
Proceeds from Investment Sales	$ 588.5	$ 433.9	$ 1,818.4	$ 1,556.6
Purchases of Investments	601.6	436.6	1,854.8	1,586.3
Gross Realized Gains on Investment Sales	24.6	9.6	41.3	98.3
Gross Realized Losses on Investment Sales	8.4	7.0	33.5	12.5

The base cost of fixed income securities was $1.2 billion and $1.2 billion as of September 30, 2022 and December 31, 2021, respectively. The base cost of equity securities was $647 million and $641 million as of September 30, 2022 and December 31, 2021, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2022 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 369.4
After 1 year through 5 years	393.8
After 5 years through 10 years	229.0
After 10 years	190.9
Total	$ 1,183.1

Fair Value Measurements of Financial Assets and Liabilities

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

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 55.1	$ —	$ —	$ —	$ 55.1
Other Cash Deposits (a)	—	—	—	18.1	18.1
Fixed Income Securities – Mutual Funds	145.4	—	—	—	145.4
Equity Securities – Mutual Funds (b)	38.7	—	—	—	38.7
Total Other Temporary Investments and Restricted Cash	239.2	—	—	18.1	257.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (d) (i)	31.7	1,650.1	467.7	(1,910.8)	238.7
Cash Flow Hedges:					
Commodity Hedges (c)	—	612.1	45.3	(68.9)	588.5
Interest Rate Hedges	—	9.3	—	(0.5)	8.8
Total Risk Management Assets	31.7	2,271.5	513.0	(1,980.2)	836.0
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	10.4	—	—	10.4	20.8
Fixed Income Securities:					
United States Government	—	1,115.2	—	—	1,115.2
Corporate Debt	—	60.9	—	—	60.9
State and Local Government	—	7.0	—	—	7.0
Subtotal Fixed Income Securities	—	1,183.1	—	—	1,183.1
Equity Securities – Domestic (b)	1,926.6	—	—	—	1,926.6
Total Spent Nuclear Fuel and Decommissioning Trusts	1,937.0	1,183.1	—	10.4	3,130.5
Total Assets	$ 2,207.9	$ 3,454.6	$ 513.0	$ (1,951.7)	$ 4,223.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d) (j)	$ 20.1	$ 1,227.7	$ 240.5	$ (1,063.9)	$ 424.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	83.7	0.9	(68.9)	15.7
Interest Rate Hedges	—	0.5	—	(0.5)	—
Fair Value Hedges	—	135.4	—	—	135.4
Total Risk Management Liabilities	$ 20.1	$ 1,447.3	$ 241.4	$ (1,133.3)	$ 575.5

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 48.0	$ —	$ —	$ —	$ 48.0
Other Cash Deposits (a)	—	—	—	10.0	10.0
Fixed Income Securities – Mutual Funds	154.8	—	—	—	154.8
Equity Securities – Mutual Funds (b)	55.6	—	—	—	55.6
Total Other Temporary Investments and Restricted Cash	258.4	—	—	10.0	268.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (f) (i)	7.4	648.5	226.3	(642.4)	239.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	242.9	19.2	(41.7)	220.4
Fair Value Hedges	—	1.2	—	—	1.2
Total Risk Management Assets	7.4	892.6	245.5	(684.1)	461.4
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	77.7	—	—	7.0	84.7
Fixed Income Securities:					
United States Government	—	1,156.4	—	—	1,156.4
Corporate Debt	—	76.7	—	—	76.7
State and Local Government	—	7.3	—	—	7.3
Subtotal Fixed Income Securities	—	1,240.4	—	—	1,240.4
Equity Securities – Domestic (b)	2,541.9	—	—	—	2,541.9
Total Spent Nuclear Fuel and Decommissioning Trusts	2,619.6	1,240.4	—	7.0	3,867.0
Other Investments (h)	28.8	14.9	—	—	43.7
Total Assets	$ 2,914.2	$ 2,147.9	$ 245.5	$ (667.1)	$ 4,640.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f) (j)	$ 5.3	$ 485.0	$ 147.6	$ (383.2)	$ 254.7
Cash Flow Hedges:					
Commodity Hedges (c)	—	54.0	0.6	(41.7)	12.9
Fair Value Hedges	—	38.1	—	—	38.1
Total Risk Management Liabilities	$ 5.3	$ 577.1	$ 148.2	$ (424.9)	$ 305.7

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 47.7	$ —	$ —	$ —	$ 47.7
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.1	—	0.2	0.3
Total Assets	$ 47.7	$ 0.1	$ —	$ 0.2	$ 48.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.1	$ —	$ —	$ 0.1

December 31, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 30.4	$ —	$ —	$ —	$ 30.4
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.6	—	(0.6)	—
Total Assets	$ 30.4	$ 0.6	$ —	$ (0.6)	$ 30.4

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 7.4	$ —	$ —	$ —	$ 7.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.9	106.7	(0.8)	106.8
Total Assets	$ 7.4	$ 0.9	$ 106.7	$ (0.8)	$ 114.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.7	$ 0.1	$ (0.8)	$ —

December 31, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 17.6	$ —	$ —	$ —	$ 17.6
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	5.8	42.0	(5.8)	42.0
Total Assets	$ 17.6	$ 5.8	$ 42.0	$ (5.8)	$ 59.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 7.2	$ 0.3	$ (6.7)	$ 0.8

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2022

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 2.4	$ 10.3	$ (1.1)	$ 11.6
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	10.4	—	—	10.4	20.8
Fixed Income Securities:					
United States Government	—	1,115.2	—	—	1,115.2
Corporate Debt	—	60.9	—	—	60.9
State and Local Government	—	7.0	—	—	7.0
Subtotal Fixed Income Securities	—	1,183.1	—	—	1,183.1
Equity Securities - Domestic (b)	1,926.6	—	—	—	1,926.6
Total Spent Nuclear Fuel and Decommissioning Trusts	1,937.0	1,183.1	—	10.4	3,130.5
Total Assets	$ 1,937.0	$ 1,185.5	$ 10.3	$ 9.3	$ 3,142.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.5	$ 0.7	$ (1.2)	$ —

December 31, 2021

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 3.8	$ 7.6	$ (8.1)	$ 3.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	77.7	—	—	7.0	84.7
Fixed Income Securities:					
United States Government	—	1,156.4	—	—	1,156.4
Corporate Debt	—	76.7	—	—	76.7
State and Local Government	—	7.3	—	—	7.3
Subtotal Fixed Income Securities	—	1,240.4	—	—	1,240.4
Equity Securities - Domestic (b)	2,541.9	—	—	—	2,541.9
Total Spent Nuclear Fuel and Decommissioning Trusts	2,619.6	1,240.4	—	7.0	3,867.0
Total Assets	$ 2,619.6	$ 1,244.2	$ 7.6	$ (1.1)	$ 3,870.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 6.7	$ 8.3	$ (10.0)	$ 5.0

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.1	$ —	$ 2.0	$ 2.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.1	$ 43.2	$ 1.8	$ 45.1

December 31, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.5	$ —	$ (0.5)	$ —
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (g)	$ —	$ —	$ 92.5	$ —	$ 92.5

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 45.2	$ (0.7)	$ 44.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.8	$ (0.8)	$ —

December 31, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 12.2	$ (0.4)	$ 12.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 3.7	$ 0.1	$ (0.1)	$ 3.7

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.1	$ 37.0	$ (0.7)	$ 36.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.8	$ (0.8)	$ —

December 31, 2021

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 11.0	$ (0.4)	$ 10.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 2.1	$ 0.1	$ (0.1)	$ 2.1

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or third-parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(d) The September 30, 2022 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $2 million in 2022 and $9 million in periods 2023-2025; Level 2 matures $47 million in 2022, $363 million in periods 2023-2025, $10 million in periods 2026-2027 and $3 million in periods 2028-2033; Level 3 matures $87 million in 2022, $139 million in periods 2023-2025, $18 million in periods 2026-2027 and $(2) million in periods 2028-2033. 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, 2021 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $1 million in 2022 and $1 million in periods 2023-2025; Level 2 matures $42 million in 2022, $109 million in periods 2023-2025, $10 million in periods 2026-2027 and $3 million in periods 2028-2033; Level 3 matures $82 million in 2022, $10 million in periods 2023-2025, $9 million in periods 2026-2027 and $(17) million in periods 2028-2033. 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 in the 2021 Annual Report for additional information.
(i) Amount excludes Risk Management Assets of $14.4 million and $6 million as of September 30, 2022 and December 31, 2021, respectively, classified as Assets Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.
(j) Amount excludes Risk Management Liabilities of $0 and $0.1 million as of September 30, 2022 and December 31, 2021, respectively, classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 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:

Three Months Ended September 30, 2022	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of June 30, 2022	$ 270.4	$ 79.6	$ 9.8	$ (48.4)	$ 64.5	$ 45.4
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	64.3	20.1	2.1	0.3	23.8	15.4
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(12.6)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	13.1	—	—	—	—	—
Settlements	(138.3)	(34.6)	(4.8)	(1.1)	(49.1)	(31.6)
Transfers into Level 3 (d) (e)	(0.5)	—	—	—	—	—
Transfers out of Level 3 (e)	3.5	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	72.5	41.5	2.5	6.0	5.2	7.0
Assets and Liabilities Held for Sale related to KPCo (g)	(0.8)	—	—	—	—	—
Balance as of September 30, 2022	$ 271.6	$ 106.6	$ 9.6	$ (43.2)	$ 44.4	$ 36.2

Three Months Ended September 30, 2021	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of June 30, 2021	$ 101.2	$ 36.6	$ 7.3	$ (105.4)	$ 22.9	$ 14.6
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	27.5	4.0	0.1	0.1	13.5	5.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	2.9	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	17.8	—	—	—	—	—
Settlements	(54.5)	(10.5)	(3.8)	0.9	(20.6)	(9.8)
Transfers into Level 3 (d) (e)	(5.8)	—	—	—	—	—
Transfers out of Level 3 (e)	(4.1)	0.1	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	44.0	15.7	(0.3)	14.0	2.7	9.0
Balance as of September 30, 2021	$ 129.0	$ 45.9	$ 3.3	$ (90.4)	$ 18.5	$ 19.6

Nine Months Ended September 30, 2022	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2021	$ 97.3	$ 41.7	$ (0.7)	$ (92.5)	$ 12.1	$ 10.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	69.3	3.0	3.7	4.6	24.2	35.8
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(44.6)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	29.4	—	—	—	—	—
Settlements	(153.8)	(44.7)	(3.0)	0.2	(36.3)	(45.0)
Transfers into Level 3 (d) (e)	1.7	—	—	—	—	—
Transfers out of Level 3 (e)	13.2	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	267.6	106.6	9.6	44.5	44.4	34.5
Assets and Liabilities Held for Sale related to KPCo (g)	(8.5)	—	—	—	—	—
Balance as of September 30, 2022	$ 271.6	$ 106.6	$ 9.6	$ (43.2)	$ 44.4	$ 36.2

Nine Months Ended September 30, 2021	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2020	$ 113.3	$ 19.3	$ 2.1	$ (110.3)	$ 10.3	$ 1.6
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	68.9	38.8	0.4	0.4	16.1	9.5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(64.1)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	35.5	—	—	—	—	—
Settlements	(113.3)	(58.2)	(2.5)	5.8	(26.4)	(13.0)
Transfers into Level 3 (d) (e)	(0.2)	—	—	—	—	—
Transfers out of Level 3 (e)	(26.2)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	115.1	46.0	3.3	13.7	18.5	21.5
Balance as of September 30, 2021	$ 129.0	$ 45.9	$ 3.3	$ (90.4)	$ 18.5	$ 19.6

(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 changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses or accounts payable.
(g) Amount represents Risk Management Assets classified as Assets Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

AEP

Significant Unobservable Inputs
September 30, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ 292.7	$ 230.6	Discounted Cash Flow	Forward Market Price (a)	$ (4.31)	$ 172.05	$ 49.58
Natural Gas Contracts	6.9	—	Discounted Cash Flow	Forward Market Price (b)	3.22	7.37	5.92
FTRs (d) (e)	213.4	10.8	Discounted Cash Flow	Forward Market Price (a)	(37.97)	27.55	0.99
Total	$ 513.0	$ 241.4					

December 31, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts (f)	$ 164.4	$ 135.2	Discounted Cash Flow	Forward Market Price (a)	$ 10.30	$ 76.70	$ 37.11
Natural Gas Contracts	3.6	—	Discounted Cash Flow	Forward Market Price (b)	3.11	4.02	3.47
FTRs (g) (h)	77.5	13.0	Discounted Cash Flow	Forward Market Price (a)	(23.93)	26.38	0.86
Total	$ 245.5	$ 148.2					

APCo

Significant Unobservable Inputs
September 30, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 106.7	$ 0.1	Discounted Cash Flow	Forward Market Price	$ (2.01)	$ 20.64	$ 3.75

December 31, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 0.3	Discounted Cash Flow	Forward Market Price	$ 32.20	$ 56.54	$ 44.77
FTRs	42.0	—	Discounted Cash Flow	Forward Market Price	(0.30)	26.38	2.63
Total	$ 42.0	$ 0.3					

I&M

Significant Unobservable Inputs
September 30, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 10.3	$ 0.7	Discounted Cash Flow	Forward Market Price	$ 0.21	$ 17.73	$ 1.61

December 31, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 0.2	Discounted Cash Flow	Forward Market Price	$ 32.20	$ 56.54	$ 44.77
FTRs	7.6	8.1	Discounted Cash Flow	Forward Market Price	(5.45)	17.78	(0.12)
Total	$ 7.6	$ 8.3					

OPCo

Significant Unobservable Inputs
September 30, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 43.2	Discounted Cash Flow	Forward Market Price	$ 1.65	$ 143.38	$ 47.12

December 31, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
Energy Contracts	$ —	$ 92.5	Discounted Cash Flow	Forward Market Price	$ 14.26	$ 52.98	$ 30.68

PSO

Significant Unobservable Inputs
September 30, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 45.2	$ 0.8	Discounted Cash Flow	Forward Market Price	$ (36.83)	$ 5.65	$ (7.55)

December 31, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (c)
	(in millions)						
FTRs	$ 12.2	$ 0.1	Discounted Cash Flow	Forward Market Price	$ (18.39)	$ 1.87	$ (2.57)

SWEPCo

Significant Unobservable Inputs
September 30, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ 6.9	$ —	Discounted Cash Flow	Forward Market Price (b)	$ 6.15	$ 7.37	$ 6.94
FTRs	30.1	0.8	Discounted Cash Flow	Forward Market Price (a)	(36.83)	5.65	(7.55)
Total	$ 37.0	$ 0.8					

December 31, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input	Low	High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ 3.6	$ —	Discounted Cash Flow	Forward Market Price (b)	$ 3.11	$ 4.02	$ 3.47
FTRs	7.4	0.1	Discounted Cash Flow	Forward Market Price (a)	(18.39)	1.87	(2.57)
Total	$ 11.0	$ 0.1					

(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) Amount excludes Risk Management Assets of $14.4 million classified as Assets Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.
(e) Amount excludes Risk Management Liabilities of $0.1 million classified as Liabilities Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.
(f) Amount excludes Risk Management Liabilities of $0.1 million classified as Liabilities Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.
(g) Amount excludes Risk Management Assets of $6 million classified as Assets Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.
(h) Amount excludes Risk Management Liabilities of $0.5 million classified as Liabilities Held for Sale on the balance sheets. See “Disposition of KPCo and KTCo” section of Note 6 for additional information.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts and FTRs for the Registrants as of September 30, 2022 and December 31, 2021:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

11. INCOME TAXES

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

Effective Tax Rates (ETR)

The Registrants' interim ETR reflect the estimated annual ETR for 2022 and 2021, adjusted for tax expense associated with certain discrete items.

The Registrants include the amortization of Excess ADIT not subject to normalization requirements in the annual estimated ETR when regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings instruct the Registrants to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, the Registrants recognize the tax benefit discretely in the period recorded. The annual amount of Excess ADIT approved by the Registrant's regulatory commissions may not impact the ETR ratably during each interim period due to the variability of pretax book income between interim periods and the application of an annual estimated ETR.

The ETR for each of the Registrants are included in the following tables:

	Three Months Ended September 30, 2022							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	(0.8)%	0.5 %	2.6 %	(6.2)%	2.7 %	0.7 %	3.0 %	(5.3) %
Tax Reform Excess ADIT Reversal	(9.7)%	(2.0)%	0.3 %	(8.6)%	(13.3)%	(6.2)%	(21.9)%	(4.6) %
Production and Investment Tax Credits	(12.0)%	(0.4)%	— %	—%	—%	—%	(43.7)%	(24.1) %
Flow Through	(0.3)%	0.2 %	0.3 %	(0.7)%	(1.5)%	0.4 %	0.4 %	(1.3) %
AFUDC Equity	(1.4)%	(1.2)%	(1.9) %	(0.4)%	(0.6)%	(0.8)%	(0.4)%	(0.2) %
Discrete Tax Adjustments	(0.2)%	—%	— %	—%	—%	—%	—%	— %
Other	1.0 %	0.2 %	0.2 %	—%	(0.5)%	0.2 %	0.2 %	(0.2) %
Effective Income Tax Rate	(2.4)%	18.3 %	22.5 %	5.1 %	7.8 %	15.3 %	(41.4)%	(14.7) %

	Three Months Ended September 30, 2021							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	0.6 %	0.3 %	3.0 %	(0.3)%	1.9 %	1.2 %	5.0 %	(6.9) %
Tax Reform Excess ADIT Reversal	(8.5)%	(6.3)%	0.3 %	(14.2)%	(16.1)%	(8.9)%	(19.8)%	(4.2) %
Production and Investment Tax Credits	(4.7)%	(0.3)%	— %	(0.2)%	(2.0)%	—%	(8.9)%	(5.4) %
Flow Through	—%	0.3 %	0.3 %	0.4 %	(2.8)%	0.6 %	0.7 %	(0.2) %
AFUDC Equity	(1.2)%	(1.0)%	(2.2) %	(1.8)%	(1.0)%	(0.3)%	(0.2)%	(0.5) %
Parent Company Loss Benefit	—%	(1.1)%	(2.3) %	(1.2)%	(3.6)%	—%	—%	0.7 %
Discrete Tax Adjustments	0.2 %	—%	— %	—%	—%	—%	—%	1.2 %
Other	0.7 %	(0.1)%	0.1 %	0.3 %	0.8 %	—%	(0.1)%	(0.2) %
Effective Income Tax Rate	8.1 %	12.8 %	20.2 %	4.0 %	(1.8)%	13.6 %	(2.3)%	5.5 %

	Nine Months Ended September 30, 2022							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	0.7 %	0.5 %	2.7 %	(0.8)%	1.3 %	0.8 %	3.2 %	(1.5) %
Tax Reform Excess ADIT Reversal	(7.8)%	(2.0)%	0.3 %	(10.3)%	(15.7)%	(7.3)%	(20.8)%	(4.8) %
Production and Investment Tax Credits	(8.7)%	(0.4)%	— %	—%	(1.4)%	—%	(39.5)%	(22.5) %
Flow Through	—%	0.2 %	0.3 %	0.2 %	(1.6)%	0.5 %	0.3 %	(0.8) %
AFUDC Equity	(1.1)%	(1.2)%	(1.9) %	(0.8)%	(0.8)%	(0.7)%	(0.4)%	(0.4) %
Discrete Tax Adjustments	(0.2)%	—%	— %	(1.8)%	—%	—%	—%	0.3 %
Other	0.6 %	0.1 %	0.1 %	—%	0.2 %	0.1 %	0.2 %	— %
Effective Income Tax Rate	4.5 %	18.2 %	22.5 %	7.5 %	3.0 %	14.4 %	(36.0)%	(8.7) %

	Nine Months Ended September 30, 2021							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	1.2 %	0.3 %	2.8 %	1.5 %	1.6 %	0.8 %	4.8 %	(3.4) %
Tax Reform Excess ADIT Reversal	(8.9)%	(7.2)%	0.3 %	(15.2)%	(17.7)%	(9.1)%	(19.8)%	(4.3) %
Production and Investment Tax Credits	(4.9)%	(0.3)%	— %	—%	(2.2)%	—%	(8.1)%	(4.6) %
Flow Through	0.2 %	0.3 %	0.3 %	1.7 %	(3.0)%	0.9 %	0.7 %	(0.2) %
AFUDC Equity	(1.1)%	(1.1)%	(1.9) %	(1.2)%	(1.0)%	(0.8)%	(0.3)%	(0.6) %
Parent Company Loss Benefit	—%	(0.7)%	(1.9) %	(1.3)%	(2.8)%	—%	—%	— %
Discrete Tax Adjustments	1.1 %	—%	— %	—%	—%	(1.3)%	(0.9)%	0.6 %
Other	0.1 %	—%	— %	0.1 %	0.4 %	0.2 %	(0.2)%	(0.1) %
Effective Income Tax Rate	8.7 %	12.3 %	20.6 %	6.6 %	(3.7)%	11.7 %	(2.8)%	8.4 %

Federal and State 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 through 2017 federal returns. In the first quarter of 2020, the IRS notified AEP that it was beginning an examination of these amended returns, including the net operating loss carryback to 2015 that originated in the 2017 return. As of September 30, 2022, the IRS has accepted the 2014-2016 amended tax returns as filed which completes the IRS audit of these tax years. Additionally, AEP has received and agreed to two proposed adjustments on the 2017 tax return, which were immaterial. AEP has agreed to extend the statute of limitations on the 2017 and 2018 tax return to December 31, 2023 to allow time for the audit to be completed and the Congressional Joint Committee on Taxation to approve the associated refund claim.

AEP and subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns, and AEP and subsidiaries are currently under examination in several state and local jurisdictions. Generally, the statutes of limitations have expired for tax years prior to 2017. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Federal Legislation

On August 16, 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022 or IRA. Most notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer of tax credits to third parties for cash. With the exception of PTCs and ITCs, this legislation is prospective and has no material impact on the current period financial statements. As significant guidance from Treasury and the IRS is expected on the tax provisions in the IRA, AEP will continue to monitor any issued guidance and evaluate the impact on future net income, cash flows and financial condition.

12. FINANCING ACTIVITIES

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

Common Stock (Applies to AEP)

At-the-Market (ATM) Program

In 2020, AEP filed a prospectus supplement and executed an Equity Distribution Agreement, 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 nine months ended September 30, 2022.

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding, net of issuance costs and premiums or discounts:

Type of Debt	September 30, 2022	December 31, 2021
	(in millions)	
Senior Unsecured Notes	$ 28,892.7	$ 27,497.3
Pollution Control Bonds	1,804.9	1,804.5
Notes Payable	218.0	211.3
Securitization Bonds	524.8	603.5
Spent Nuclear Fuel Obligation (a)	283.2	281.3
Junior Subordinated Notes (b)	2,377.3	2,373.0
Other Long-term Debt	949.2	683.6
Total Long-term Debt Outstanding	35,050.1	33,454.5
Long-term Debt Due Within One Year (c)	1,403.5	2,153.8
Long-term Debt (d)	$ 33,646.6	$ 31,300.7

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for SNF disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $326 million and $329 million as of September 30, 2022 and December 31, 2021, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.
(b) See "Equity Units" section below for additional information.
(c) Amount excludes $215 million and $200 million as of September 30, 2022 and December 31, 2021, respectively, of Long-term Debt Due Within One Year classified as Liabilities Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.
(d) Amount excludes $963 million and $903 million as of September 30, 2022 and December 31, 2021, respectively, of Long-term Debt classified as Liabilities Held for Sale on the balance sheet. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2022 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)		Interest Rate	Due Date
Issuances:		**(in millions)**		**(%)**	
AEP Texas	Other Long-term Debt	$	200.0	Variable	2025
AEP Texas	Senior Unsecured Notes		500.0	4.70	2032
AEP Texas	Senior Unsecured Notes		500.0	5.25	2052
AEPTCo	Senior Unsecured Notes		550.0	4.50	2052
APCo	Other Long-term Debt		100.0	Variable	2023
APCo	Pollution Control Bonds		104.4	3.75	2025
APCo	Senior Unsecured Notes		500.0	4.50	2032
I&M	Notes Payable		72.8	3.44	2026
PSO	Other Long-term Debt		500.0	Variable	2022
Non-Registrant:					
AEGCo	Pollution Control Bonds		45.0	3.13	2025
KPCo	Other Long-term Debt		150.0	Variable	2023
Transource Energy	Other Long-term Debt		5.0	Variable	2023
WPCo	Other Long-term Debt		165.0	Variable	2024
WPCo	Pollution Control Bonds		65.0	3.00	2027
Total Issuances		$	3,457.2		

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		**(in millions)**	**(%)**	
AEP Texas	Other Long-term Debt	$ 200.0	Variable	2022
AEP Texas	Senior Unsecured Notes	400.0	2.40	2022
AEP Texas	Senior Unsecured Notes	25.0	3.27	2022
AEP Texas	Securitization Bonds	30.6	2.85	2024
AEP Texas	Securitization Bonds	23.0	2.06	2025
APCo	Pollution Control Bonds	104.4	2.63	2022
APCo	Securitization Bonds	25.9	2.01	2023
APCo	Other Long-term Debt	0.1	13.72	2026
I&M	Notes Payable	3.4	Variable	2022
I&M	Notes Payable	1.3	Variable	2022
I&M	Notes Payable	6.7	Variable	2023
I&M	Notes Payable	10.8	Variable	2024
I&M	Notes Payable	18.9	0.93	2025
I&M	Notes Payable	13.7	Variable	2025
I&M	Notes Payable	8.0	3.44	2026
I&M	Other Long-term Debt	1.7	6.00	2025
OPCo	Other Long-term Debt	0.1	1.15	2028
PSO	Other Long-term Debt	500.0	Variable	2022
PSO	Other Long-term Debt	0.4	3.00	2027
SWEPCo	Other Long-term Debt	1.5	4.68	2028
SWEPCo	Notes Payable	3.2	4.58	2032
Non-Registrant:				
AEGCo	Pollution Control Bonds	45.0	1.35	2022
KPCo	Other Long-term Debt	75.0	Variable	2022
Transource Energy	Senior Unsecured Notes	2.4	2.75	2050
WPCo	Pollution Control Bonds	65.0	3.00	2022
WPCo	Senior Unsecured Notes	113.0	3.36	2022
Total Retirements and Principal Payments		$ 1,679.1		

Long-term Debt Subsequent Event

In October 2022, AEGCo retired $120 million of Other Long-term Debt.

In October 2022, AEGCo issued $80 million of variable rate Other Long-term Debt due in 2024.

In October 2022, AEPTCo retired $104 million of Senior Unsecured Notes.

In October 2022, APCo retired $100 million of Pollution Control Bonds.

In October 2022, I&M retired $7 million of Notes Payable related to DCC Fuel.

In October 2022, Transource Energy issued $64 million of variable rate Other Long-term Debt due in 2025.

In October 2022, Transource Energy retired $64 million of Other Long-term Debt.

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 settled after three years in 2022. In January 2022, AEP successfully remarketed the notes on behalf of holders of the corporate units and did not directly receive any proceeds therefrom. Instead, the holders of the corporate units used the debt remarketing proceeds to settle the forward equity purchase contract with AEP. The interest rate on the notes was reset to 2.031% with the maturity remaining in 2024. In March 2022, AEP issued 8,970,920 shares of AEP common stock and received proceeds totaling $805 million under the settlement of the forward equity purchase contract. AEP common stock held in treasury was used to settle the forward equity purchase contract.

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. AEPTCo's contractually-defined priority debt was 0.5% of consolidated tangible net assets as of September 30, 2022. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreements.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings. The Federal Power Act also creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to APCo and I&M.

Certain AEP subsidiaries have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings.

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

Corporate Borrowing Program - AEP System (Applies to all Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries.The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC.The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of September 30, 2022 and December 31, 2021 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' activity and corresponding authorized borrowing limits for the nine months ended September 30, 2022 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings) from the Utility Money Pool as of September 30, 2022	Authorized Short-term Borrowing Limit
				(in millions)		
AEP Texas	$ 348.8	$ 652.3	$ 208.1	$ 319.8	$ 129.5	$ 500.0
AEPTCo	480.2	137.0	197.4	31.3	78.7 (a)	820.0 (b)
APCo	438.4	214.2	180.9	52.8	182.1	500.0
I&M	159.1	22.6	86.0	22.1	(82.3)	500.0
OPCo	147.2	246.1	59.9	86.9	(68.8)	500.0
PSO	338.3	432.5	200.9	402.8	(223.5)	400.0
SWEPCo	261.6	156.6	191.0	109.7	(156.3)	400.0

(a) Amount excludes $5 million of Advances to Affiliates classified as Assets Held for Sale on the AEPTCo balance sheet. See "Dispositions of KPCo and KTCo" section of Note 6 for additional information.
(b) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above table does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in th Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of September 30, 2022 and December 31, 2021 are included in Advances to Affiliates on the subsidiaries' balance sheets. The Nonutility Money Pool participants' activity for the nine months ended September 30, 2022 is described in the following table:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of September 30, 2022
		(in millions)	
AEP Texas	$ 6.9	$ 6.8	$ 6.8
SWEPCo	2.1	2.1	2.1

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs.The amounts of outstanding loans to and borrowings from AEP as of September 30, 2022 and December 31, 2021 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets.AEPTCo's direct borrowing and lending activity with AEP and corresponding authorized borrowing limit for the nine months ended September 30, 2022 are described in the following table:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of September 30, 2022	Loans to AEP as of September 30, 2022	Authorized Short-term Borrowing Limit	
				(in millions)			
$ 52.4	$ 141.8	$ 7.1	$ 59.6	$ 33.0	$ —	$ 50.0	(a)

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Nine Months Ended September 30, 2022	2021
Maximum Interest Rate	3.39 %	0.40 %
Minimum Interest Rate	0.10 %	0.02 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Nine Months Ended September 30, 2022	2021	Average Interest Rate for Funds Loaned to the Utility Money Pool for Nine Months Ended September 30, 2022	2021
AEP Texas	0.90 %	0.33 %	1.82 %	0.27 %
AEPTCo	1.03 %	0.32 %	2.14 %	0.07 %
APCo	1.39 %	0.28 %	2.13 %	0.28 %
I&M	1.38 %	0.32 %	1.46 %	0.25 %
OPCo	1.81 %	0.27 %	1.22 %	0.15 %
PSO	1.70 %	0.34 %	0.75 %	0.06 %
SWEPCo	1.67 %	0.28 %	0.55 %	0.38 %

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool are summarized in the following table:

	Nine Months Ended September 30, 2022			Nine Months Ended September 30, 2021		
Company	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	3.39 %	0.46 %	1.51 %	0.41 %	0.21 %	0.34 %
SWEPCo	3.39 %	0.46 %	1.52 %	0.41 %	0.21 %	0.34 %

AEPTCo's maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following table:

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
2022	3.39 %	0.46 %	3.37 %	0.46 %	1.56 %	1.38 %
2021	0.86 %	0.25 %	0.86 %	0.25 %	0.35 %	0.34 %

Short-term Debt (Applies to AEP)

Outstanding short-term debt was as follows:

		September 30, 2022		December 31, 2021	
Company	Type of Debt	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
		(dollars in millions)			
AEP	Securitized Debt for Receivables (b)	$ 750.0	1.16 %	$ 750.0	0.19 %
AEP	Commercial Paper	1,952.3	3.38 %	1,364.0	0.34 %
AEP	Term Loan	—	— %	500.0	0.81 %
	Total Short-term Debt	$ 2,702.3		$ 2,614.0	

(a) Weighted-average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables and accelerate AEP Credit's cash collections.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and was amended in September 2021 to include a $125 million and a $625 million facility. The $125 million facility was renewed in September 2022 and amended to extend the expiration date to September 2024. The $625 million facility also expires in September 2024. As of September 30, 2022, the affiliated utility subsidiaries are in compliance with all requirements under the agreement.

Accounts receivable information for AEP Credit was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	2.25 %	0.18 %	1.16 %	0.19 %
Net Uncollectible Accounts Receivable Written-Off	$ 9.5	$ 7.5	$ 23.1	$ 22.6

	September 30, 2022	December 31, 2021
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,172.5	$ 995.2
Short-term – Securitized Debt of Receivables	750.0	750.0
Delinquent Securitized Accounts Receivable	57.4	57.9
Bad Debt Reserves Related to Securitization	39.4	42.8
Unbilled Receivables Related to Securitization	252.3	307.1

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to all 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. KPCo ceased selling accounts receivable to AEP Credit in the first quarter of 2022, based on the pending sale to Liberty. As a result, in the first quarter of 2022, KPCo recorded an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit.AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreements were:

Company	September 30, 2022	December 31, 2021
	(in millions)	
APCo	$ 127.5	$ 153.1
I&M	187.8	156.9
OPCo	476.7	392.7
PSO	188.4	114.5
SWEPCo	217.0	153.0

The fees paid to AEP Credit for customer accounts receivable sold were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2022	2021 (a)	2022	2021 (a)
	(in millions)			
APCo	$ 2.8	$ 1.3	$ 5.6	$ 3.7
I&M	2.8	2.1	6.5	5.3
OPCo	7.3	4.6	22.2	3.5
PSO	2.4	1.1	4.6	2.4
SWEPCo	3.2	1.3	6.0	4.1

(a) In 2020, an increase in allowance for doubtful accounts was recognized in response to the anticipated impact of COVID-19 on the collectability of accounts receivable, which caused an increase in fees paid by the Registrants. In 2021, due to higher than expected collections of accounts receivables, allowance for doubtful accounts was adjusted resulting in the issuance of credits to offset the higher fees previously paid.

The proceeds on the sale of receivables to AEP Credit were:

Company	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
	(in millions)			
APCo	$ 360.4	$ 342.2	$ 1,114.9	$ 980.6
I&M	558.5	536.8	1,574.3	1,478.9
OPCo	874.1	668.4	2,284.0	1,867.5
PSO	588.5	460.1	1,380.4	1,068.8
SWEPCo	593.6	488.5	1,425.3	1,265.5

13. PROPERTY, PLANT AND EQUIPMENT

The disclosure in this note applies to AEP, PSO and SWEPCo.

Asset Retirement Obligations

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms, solar farms and certain coal mining facilities. The discussion below summarizes significant changes to the Registrants ARO recorded in 2022 and should be read in conjunction with the Property, Plant and Equipment note within the 2021 Annual Report.

In March 2022, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Traverse during its development and construction. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the Traverse assets in proportion to their undivided ownership interests. Traverse was placed in-service in March 2022. As a result, PSO and SWEPCo incurred additional ARO liabilities of $13 million and $15 million, respectively. See the "North Central Wind Energy Facilities" section of Note 6 for additional information. Additionally, in March 2022, SWEPCo recorded a $13 million revision due to an increase in estimated ash pond closure costs at the Pirkey Plant and the Welsh Plant. In June 2022, SWEPCo recorded a $6 million revision due to an increase in estimated reclamation costs at Sabine. In September 2022, SWEPCo recorded a $14 million revision due to an increase in estimated landfill closure costs at Pirkey Plant.

The following is a reconciliation of the aggregate carrying amounts of ARO for AEP, PSO and SWEPCo:

Company	ARO as of December 31, 2021	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of September 30, 2022
			(in millions)			
AEP (a)(b)(c)(d)(e)	$ 2,741.7	$ 82.1	$ 37.4	$ (29.4)	$ 90.9	$ 2,922.7
PSO (a)(d)	57.6	3.0	12.8	(0.6)	1.9	74.7
SWEPCo (a)(c)(d)	222.7	8.3	15.4	(16.9)	48.0	277.5

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.98 billion and $1.93 billion as of September 30, 2022 and December 31, 2021, respectively.
(c) Includes ARO related to Sabine and DHLC.
(d) Includes ARO related to asbestos removal.
(e) Includes $18 million and $18 million as of September 30, 2022 and December 31, 2021, respectively, of ARO classified as Liabilities Held for Sale on the balance sheets. See "Disposition of KPCo and KTCo" section of Note 6 for additional information.

14. REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Disaggregated Revenues from Contracts with Customers

The tables below represent AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Three Months Ended September 30, 2022						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,298.0	$ 721.9	$ —	$ —	$ —	$ —	$ 2,019.9
Commercial Revenues	725.1	373.0	—	—	—	—	1,098.1
Industrial Revenues	658.5	191.5	—	—	—	(0.3)	849.7
Other Retail Revenues	54.3	15.0	—	—	—	—	69.3
Total Retail Revenues	2,735.9	1,301.4	—	—	—	(0.3)	4,037.0
Wholesale and Competitive Retail Revenues:							
Generation Revenues	299.3	—	—	83.7	—	(0.2)	382.8
Transmission Revenues (a)	120.3	162.3	424.9	—	—	(392.7)	314.8
Renewable Generation Revenues (b)	—	—	—	44.3	—	(2.5)	41.8
Retail, Trading and Marketing Revenues	—	—	—	482.9	2.2	0.2	485.3
Total Wholesale and Competitive Retail Revenues	419.6	162.3	424.9	610.9	2.2	(395.2)	1,224.7
Other Revenues from Contracts with Customers (c)	69.7	74.5	(0.3)	1.7	24.3	(31.9)	138.0
Total Revenues from Contracts with Customers	3,225.2	1,538.2	424.6	612.6	26.5	(427.4)	5,399.7
Other Revenues:							
Alternative Revenues (b)	0.9	(13.5)	6.3	—	—	4.4	(1.9)
Other Revenues (b) (d)	0.2	5.5	—	122.8	1.8	(2.0)	128.3
Total Other Revenues	1.1	(8.0)	6.3	122.8	1.8	2.4	126.4
Total Revenues	$ 3,226.3	$ 1,530.2	$ 430.9	$ 735.4	$ 28.3	$ (425.0)	$ 5,526.1

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $342 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 Corporate and Other was $18 million. The remaining affiliated amounts were immaterial.
(d) Generation & Marketing includes economic hedge activity.

	Three Months Ended September 30, 2021						
	Vertically Integrated Utilities	**Transmission and Distribution Utilities**	**AEP Transmission Holdco**	**Generation & Marketing**	**Corporate and Other**	**Reconciling Adjustments**	**AEP Consolidated**
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,144.3	$ 598.0	$ —	$ —	$ —	$ —	$ 1,742.3
Commercial Revenues	618.9	279.9	—	—	—	—	898.8
Industrial Revenues	566.0	95.2	—	—	—	(0.1)	661.1
Other Retail Revenues	47.5	11.1	—	—	—	—	58.6
Total Retail Revenues	2,376.7	984.2	—	—	—	(0.1)	3,360.8
Wholesale and Competitive Retail Revenues:							
Generation Revenues	233.8	—	—	47.8	—	—	281.6
Transmission Revenues (a)	99.8	150.6	375.8	—	—	(317.4)	308.8
Renewable Generation Revenues (b)	—	—	—	24.1	—	(0.6)	23.5
Retail, Trading and Marketing Revenues (c)	—	—	—	397.1	0.1	(3.1)	394.1
Total Wholesale and Competitive Retail Revenues	333.6	150.6	375.8	469.0	0.1	(321.1)	1,008.0
Other Revenues from Contracts with Customers (b)	49.4	54.2	5.1	1.4	23.5	(40.1)	93.5
Total Revenues from Contracts with Customers	2,759.7	1,189.0	380.9	470.4	23.6	(361.3)	4,462.3
Other Revenues:							
Alternative Revenues (b)	0.5	6.4	10.7	—	—	(11.7)	5.9
Other Revenues (b) (d)	(0.9)	4.9	—	150.7	3.1	(3.0)	154.8
Total Other Revenues	(0.4)	11.3	10.7	150.7	3.1	(14.7)	160.7
Total Revenues	$ 2,759.3	$ 1,200.3	$ 391.6	$ 621.1	$ 26.7	$ (376.0)	$ 4,623.0

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $286 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 $4 million. The remaining affiliated amounts were immaterial.
(d) Generation & Marketing includes economic hedge activity.

	Three Months Ended September 30, 2022						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
tail Revenues:							
Residential Revenues	$ 204.0	$ —	$ 360.5	$ 238.6	$ 517.9	$ 299.6	$ 285.5
Commercial Revenues	107.1	—	161.1	154.3	266.1	153.4	182.3
Industrial Revenues	35.4	—	163.3	155.6	156.1	98.9	108.3
Other Retail Revenues	11.5	—	20.6	1.2	3.5	30.1	0.6
tal Retail Revenues	358.0	—	705.5	549.7	943.6	582.0	576.7
ıolesale Revenues:							
Generation Revenues (a)	—	—	107.9	126.3	—	9.4	87.6
Transmission Revenues (b)	140.8	411.7	41.5	8.8	21.5	10.2	42.3
tal Wholesale Revenues	140.8	411.7	149.4	135.1	21.5	19.6	129.9
Other Revenues from Contracts with Customers (c)	9.5	(0.3)	33.7	30.6	64.8	6.4	7.6
Total Revenues from Contracts with Customers	508.3	411.4	888.6	715.4	1,029.9	608.0	714.2
her Revenues:							
Alternative Revenues (d)	0.6	7.1	—	—	(14.1)	0.2	3.3
Other Revenues (d)	—	—	0.3	—	5.5	—	—
tal Other Revenues	0.6	7.1	0.3	—	(8.6)	0.2	3.3
tal Revenues	$ 508.9	$ 418.5	$ 888.9	$ 715.4	$ 1,021.3	$ 608.2	$ 717.5

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $44 million primarily related to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $339 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $15 million primarily related to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	Three Months Ended September 30, 2021						
	(in millions)						
etail Revenues:							
Residential Revenues	$ 172.5	$ —	$ 340.1	$ 231.7	$ 425.4	$ 236.8	$ 230.9
Commercial Revenues	89.1	—	146.9	143.9	190.8	120.9	145.4
Industrial Revenues	25.4	—	154.8	146.8	69.8	77.1	85.4
Other Retail Revenues	8.2	—	18.6	1.3	3.1	23.4	2.3
otal Retail Revenues	295.2	—	660.4	523.7	689.1	458.2	464.0
holesale Revenues:							
Generation Revenues (a)	—	—	83.7	80.2	—	7.2	77.1
Transmission Revenues (b)	131.5	360.1	35.2	8.7	19.1	10.6	37.1
otal Wholesale Revenues	131.5	360.1	118.9	88.9	19.1	17.8	114.2
Other Revenues from Contracts with Customers (c)	6.8	5.0	22.5	24.2	47.3	8.3	6.1
Total Revenues from Contracts with Customers	433.5	365.1	801.8	636.8	755.5	484.3	584.3
ther Revenues:							
Alternative Revenues (d)	(0.9)	11.9	2.2	(1.1)	7.3	(0.5)	(0.2)
Other Revenues (d)	—	—	—	—	4.9	—	—
otal Other Revenues	(0.9)	11.9	2.2	(1.1)	12.2	(0.5)	(0.2)
otal Revenues	$ 432.6	$ 377.0	$ 804.0	$ 635.7	$ 767.7	$ 483.8	$ 584.1

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $30 million primarily related to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $281 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $17 million primarily related to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	Nine Months Ended September 30, 2022						
	(in millions)						
tail Revenues:							
Residential Revenues	$ 3,428.1	$ 1,884.1	$ —	$ —	$ —	$ —	$ 5,312.2
Commercial Revenues	1,922.8	994.4	—	—	—	—	2,917.2
Industrial Revenues (b)	1,863.3	487.3	—	—	—	(0.7)	2,349.9
Other Retail Revenues	154.6	39.4	—	—	—	—	194.0
al Retail Revenues	7,368.8	3,405.2	—	—	—	(0.7)	10,773.3
Wholesale and Competitive Retail Revenues:							
Generation Revenues (b)	674.8	—	—	207.0	—	(0.1)	881.7
Transmission Revenues (a)	334.4	482.1	1,261.0	—	—	(1,086.5)	991.0
Renewable Generation Revenues (b)	—	—	—	104.9	—	(6.2)	98.7
Retail, Trading and Marketing Revenues (c)	—	—	—	1,280.0	6.7	(11.1)	1,275.6
Total Wholesale and Competitive Retail Revenues	1,009.2	482.1	1,261.0	1,591.9	6.7	(1,103.9)	3,247.0
Other Revenues from Contracts with Customers (d)	180.5	194.2	(0.3)	11.9	59.1	(71.6)	373.8
Total Revenues from Contracts with Customers	8,558.5	4,081.5	1,260.7	1,603.8	65.8	(1,176.2)	14,394.1
her Revenues:							
Alternative Revenues (b)	3.4	(21.5)	(39.6)	—	—	(7.4)	(65.1)
Other Revenues (b) (e)	0.3	18.6	—	410.5	6.9	(6.9)	429.4
al Other Revenues	3.7	(2.9)	(39.6)	410.5	6.9	(14.3)	364.3
al Revenues	$ 8,562.2	$ 4,078.6	$ 1,221.1	$ 2,014.3	$ 72.7	$ (1,190.5)	$ 14,758.4

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $1 billion. The affiliated revenue for Vertically Integrated Utilities was $120 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 $11 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $36 million. The remaining affiliated amounts were immaterial.
(e) Generation & Marketing includes economic hedge activity.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	Nine Months Ended September 30, 2021						
	(in millions)						
tail Revenues:							
Residential Revenues	$ 3,016.2	$ 1,641.2	$ —	$ —	$ —	$ —	$ 4,657.4
Commercial Revenues	1,642.0	804.1	—	—	—	—	2,446.1
Industrial Revenues	1,602.5	283.8	—	—	—	(0.5)	1,885.8
Other Retail Revenues	125.9	32.4	—	—	—	—	158.3
tal Retail Revenues	6,386.6	2,761.5	—	—	—	(0.5)	9,147.6
Wholesale and Competitive Retail Revenues:							
Generation Revenues	757.1	—	—	119.4	—	—	876.5
Transmission Revenues (a)	267.3	420.7	1,092.1	—	—	(901.5)	878.6
Renewable Generation Revenues (b)	—	—	—	66.7	—	(1.7)	65.0
Retail, Trading and Marketing Revenues (c)	—	—	—	1,325.6	0.6	(48.5)	1,277.7
Total Wholesale and Competitive Retail Revenues	1,024.4	420.7	1,092.1	1,511.7	0.6	(951.7)	3,097.8
Other Revenues from Contracts with Customers (b)	136.1	149.3	12.5	4.9	46.1	(87.9)	261.0
Total Revenues from Contracts with Customers	7,547.1	3,331.5	1,104.6	1,516.6	46.7	(1,040.1)	12,506.4
her Revenues:							
Alternative Revenues (b)	10.7	46.1	42.2	—	—	(63.5)	35.5
Other Revenues (b) (d)	(0.6)	14.2	—	175.3	8.4	(8.6)	188.7
tal Other Revenues	10.1	60.3	42.2	175.3	8.4	(72.1)	224.2
tal Revenues	$ 7,557.2	$ 3,391.8	$ 1,146.8	$ 1,691.9	$ 55.1	$ (1,112.2)	$ 12,730.6

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $835 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 $49 million. The remaining affiliated amounts were immaterial.
(d) Generation & Marketing includes economic hedge activity.

	Nine Months Ended September 30, 2022						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
tail Revenues:							
Residential Revenues	$ 520.8	$ —	$ 1,131.7	$ 665.6	$ 1,363.3	$ 650.7	$ 650.0
Commercial Revenues	312.6	—	467.6	419.5	681.9	372.1	458.8
Industrial Revenues (d)	102.6	—	479.0	452.1	384.8	270.0	290.1
Other Retail Revenues	29.2	—	61.4	3.7	10.2	77.1	7.4
tal Retail Revenues	965.2	—	2,139.7	1,540.9	2,440.2	1,369.9	1,406.3
olesale Revenues:							
Generation Revenues (a)	—	—	227.6	310.9	—	19.2	206.2
Transmission Revenues (b)	417.7	1,218.1	123.4	26.3	64.4	28.9	116.8
tal Wholesale Revenues	417.7	1,218.1	351.0	337.2	64.4	48.1	323.0
Other Revenues from Contracts with Customers (c)	24.4	(0.4)	78.6	86.3	169.6	21.4	18.9
Total Revenues from Contracts with Customers	1,407.3	1,217.7	2,569.3	1,964.4	2,674.2	1,439.4	1,748.2
her Revenues:							
Alternative Revenues (d)	(2.9)	(34.4)	0.1	7.3	(18.6)	(0.7)	0.7
Other Revenues (d)	—	—	0.4	(0.1)	18.6	—	—
tal Other Revenues	(2.9)	(34.4)	0.5	7.2	—	(0.7)	0.7
tal Revenues	$ 1,404.4	$ 1,183.3	$ 2,569.8	$ 1,971.6	$ 2,674.2	$ 1,438.7	$ 1,748.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $122 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 $992 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $44 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

	Nine Months Ended September 30, 2021						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 423.7	$ —	$ 1,025.0	$ 624.4	$ 1,217.5	$ 516.4	$ 547.1
Commercial Revenues	265.2	—	409.5	384.5	538.9	286.8	385.4
Industrial Revenues	81.6	—	433.4	418.9	202.2	202.1	247.1
Other Retail Revenues	23.1	—	51.7	3.9	9.4	58.2	7.2
Total Retail Revenues	793.6	—	1,919.6	1,431.7	1,968.0	1,063.5	1,186.8
Wholesale Revenues:							
Generation Revenues (a)	—	—	231.2	248.1	—	6.8	326.2
Transmission Revenues (b)	364.5	1,045.2	94.1	25.3	56.2	28.8	94.5
Total Wholesale Revenues	364.5	1,045.2	325.3	273.4	56.2	35.6	420.7
Other Revenues from Contracts with Customers (c)	35.4	12.5	43.6	81.9	113.8	24.8	17.7
Total Revenues from Contracts with Customers	1,193.5	1,057.7	2,288.5	1,787.0	2,138.0	1,123.9	1,625.2
Other Revenues:							
Alternative Revenues (d)	1.8	46.5	9.5	(3.0)	44.3	0.5	5.1
Other Revenues (d)	—	—	—	—	14.2	—	—
Total Other Revenues	1.8	46.5	9.5	(3.0)	58.5	0.5	5.1
Total Revenues	$ 1,195.3	$ 1,104.2	$ 2,298.0	$ 1,784.0	$ 2,196.5	$ 1,124.4	$ 1,630.3

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $90 million primarily relating to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $823 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $46 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

Fixed Performance Obligations

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of September 30, 2022. 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	2022	2023-2024	2025-2026	After 2026	Total
			(in millions)		
AEP	$ 318.7	$ 172.1	$ 157.8	$ 96.9	$ 745.5
AEP Texas	145.8	—	—	—	145.8
AEPTCo	369.4	—	—	—	369.4
APCo	50.1	33.7	26.6	11.5	121.9
I&M	9.7	13.6	9.2	4.5	37.0
OPCo	19.2	3.4	—	—	22.6
PSO	3.4	—	—	—	3.4
SWEPCo	10.9	—	—	—	10.9

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have material contract assets as of September 30, 2022 and December 31, 2021.

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 sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have material contract liabilities as of September 30, 2022 and December 31, 2021.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrant Subsidiaries' balance sheets within the Accounts Receivable - Customers line item. The Registrant Subsidiaries' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of September 30, 2022 and December 31, 2021. See "Securitized Accounts Receivable - AEP Credit" section of Note 12 for additional information.

The following table represents the amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on the Registrant Subsidiaries' balance sheets:

Company	September 30, 2022	December 31, 2021
	(in millions)	
AEP Texas	$ —	$ 0.4
AEPTCo	110.6	95.5
APCo	65.8	117.8
I&M	51.1	61.2
OPCo	61.5	51.7
PSO	36.8	18.8
SWEPCo	20.2	24.7

CONTROLS AND PROCEDURES

During the third quarter of 2022, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of September 30, 2022, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2022 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings, see “Commitments, Guarantees and Contingencies,” of Note 5 incorporated herein by reference.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2021 includes a detailed discussion of risk factors.As of September 30, 2022, the risk factors appearing in AEP’s 2021 Annual Report are supplemented and updated as follows:

Supply chain disruptions and inflation could negatively impact operations and corporate strategy. (Applies to all Registrants)

AEP’s operations and business plans depend on the global supply chain to procure the equipment, materials and other resources necessary to build and provide services in a safe and reliable manner. The delivery of components, materials, equipment and other resources that are critical to AEP’s business operations and corporate strategy has been restricted by the current domestic and global supply chain upheaval. This has resulted in the shortage of critical items. International tensions, including the ramifications of regional conflict, could further exacerbate the global supply chain upheaval. These disruptions and shortages could adversely impact business operations and corporate strategy. The constraints in the supply chain could restrict the availability and delay the construction, maintenance or repair of items that are needed to support normal operations or are required to execute AEP’s corporate strategy for continued capital investment in utility equipment. These disruptions and constraints could reduce future net income and cash flows and possibly harm AEP’s financial condition.

Supply chain disruptions have contributed to higher prices of components, materials, equipment and other needed commodities and these inflationary increases may continue in the future. The economy in the United States has encountered a material level of inflation and that has contributed to increased uncertainty in the outlook of near-term economic activity, including whether inflation will continue and at what rate. AEP typically recovers increases in capital expenses from customers through rates in regulated jurisdictions. Failure to recover increased capital costs could reduce future net income and cash flows and possibly harm AEP’s financial condition. Increases in inflation raises costs for labor, materials and services, and failure to secure these on reasonable terms may adversely impact AEP’s financial condition.

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

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

A security breach of AEP or its regulated utility businesses' physical assets or information systems, interconnected entities in RTOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system. AEP and its regulated utility businesses could be subject to financial harm associated with ransomware theft or inappropriate release of certain types of information, including sensitive customer, vendor, employee, trading or other confidential data. A successful cyber-attack on the systems that control generation, transmission, distribution or other assets could severely disrupt business operations, preventing service to customers or collection of revenues. The breach of certain business systems could affect the ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to AEP's reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. AEP and its third-party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to their technology systems and confidential data or to attempts to disrupt utility and related business operations. While there have been immaterial incidents of phishing, unauthorized access to technology systems, financial fraud, and disruption of remote access across the AEP System, there has been no material impact on business or operations from these attacks. However, AEP cannot guarantee that security efforts will detect or prevent breaches, operational incidents, or other breakdowns of technology systems and network infrastructure and cannot provide any assurance that such incidents will not have a material adverse effect in the future.

The IRA could change the rate of taxes imposed on AEP. (Applies to all Registrants)

On August 16, 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022 or IRAMost notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer o tax credits to third parties for cash. Additional guidance on the tax provisions in the IRA is expected from the Treasury and the IRS.The regulatory treatment of the impacts of this legislation will also be subject to the discretion of the FERC and state public utility commissions.Any adverse development in this legislation, including guidance from Treasury and the IRS or unfavorable regulatory treatment, could reduce future cash flows and impact financial condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations.The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of DHLC, a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act.Exhibit 95 "Mine Safety Disclosure Exhibit" contains the notices of violation and proposed assessments received by DHLC under the Mine Act for the quarter ended September 30, 2022.

Item 5. Other Information

None.

Item 6. Exhibits

The documents designated with an (*) below have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof.

Exhibit	Description	Previously Filed as Exhibit to:
APCo‡ File No. 1-3457		
4	Company Order and Officer's Certificate between APCo and The Bank of New York Mellon Trust Company, N.A. as Trustee dated August 1, 2022 establishing terms of the 4.50% Senior Notes, Series BB, due 2032.	Form 8-K dated August 1, 2022 Exhibit 4(a)

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
10	Amendment to Stock Purchase Agreement dated September 29, 2022 among AEP, AEPTCo and Liberty Utilities Co.	X		X					
31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X	X	X	X	X	X	X	X
32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code	X	X	X	X	X	X	X	X
95	Mine Safety Disclosures								X
101.INS	XBRL Instance Document	The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.							
101.SCH	XBRL Taxonomy Extension Schema	X	X	X	X	X	X	X	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X	X	X	X	X	X	X	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase	X	X	X	X	X	X	X	X
101.LAB	XBRL Taxonomy Extension Label Linkbase	X	X	X	X	X	X	X	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	X	X	X	X	X	X	X	X
104	Cover Page Interactive Data File	Formatted as Inline XBRL and contained in Exhibit 101.							

SIGNATURE

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

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

AEP TEXAS INC.
AEP TRANSMISSION COMPANY, LLC
APPALACHIAN POWER COMPANY
INDIANA MICHIGAN POWER COMPANY
OHIO POWER COMPANY
PUBLIC SERVICE COMPANY OF OKLAHOMA
SOUTHWESTERN ELECTRIC POWER COMPANY

By: /s/ Joseph M. Buonaiuto
Joseph M. Buonaiuto
Controller and Chief Accounting Officer

Date: October 27, 2022