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 **June 30, 2023**
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 July 27, 2023
American Electric Power Company, Inc.	515,176,044
	($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
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
June 30, 2023

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 Energy Supply LLC	A nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
AEP Renewables	A division of AEP Energy Supply LLC that develops and/or acquires large scale renewable projects that are backed with long-term contracts with creditworthy counter parties.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in deregulated markets.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AFUDC	Allowance for Equity Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to the under-recovered Expanded Net Energy Cost deferral balance.
Apple Blossom	Apple Blossom Wind Holdings LLC, a consolidated VIE of AEP, and tax equity partnership.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
ATM	At-the-Market.
Black Oak	Black Oak Getty Wind Holdings LLC, a consolidated VIE of AEP, and tax equity partnership.
CAA	Clean Air Act.
CCR	Coal Combustion Residual.
CO_2	Carbon dioxide and other greenhouse gases.
CO_2e	Carbon dioxide equivalent.

Term	Meaning
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.
CSAPR	Cross-State Air Pollution Rule.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel XIII, DCC Fuel XIV, DCC Fuel XV, DCC Fuel XVI, DCC Fuel XVII and DCC Fuel X 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 SWEPCoDHLC is a non-consolidated VIE of SWEPCo.
Dry Lake	Dry Lake Solar Project, a consolidated VIE whose sole purpose is to own and operate a 100 MW solar generation facility in southern Nevada in which AEP owns a 75% interest.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
ELG	Effluent Limitation Guidelines.
ENEC	Expanded Net Energy Cost.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
Equity Units	AEP's Equity Units issued in August 2020.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
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.

Term	Meaning
KTCo	AEP Kentucky Transmission Company, Inc., an affiliate of KPCo and a wholly-owned subsidiary of AEP.
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.
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 Carryforward.
NO_x	Nitrogen oxide.
OCC	Corporation Commission of the State of Oklahoma.
OHTCo	AEP Ohio Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
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.
PSA	Purchase 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.

Term	Meaning
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, jointly owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated VIE for AEP and SWEPCo.
Santa Rita East	Santa Rita East Wind Holdings, LLC, a consolidated VIE whose sole purpose is to own and operate a 302 MW wind generation facility in west Texas in which AEP owns an 85% interest.
SEC	U.S. Securities and Exchange Commission.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
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, electricity usage, supply chain issues, customers, service providers, vendors and suppliers.
- The economic impact of increased 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 and disruptions in financial markets precipitated by any cause, including failure to make progress on federal budget or debt ceiling matters or instability in the banking industry; 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, subsidiaries or tax credits, do not materialize or do not materialize at the level anticipated, 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.
- Limitations or restrictions on the amounts and types of insurance available to cover losses that might arise in connection with natural disasters or operations.
- 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, cost caps imposed by regulators and other operational commitments to regulatory commissions and customers for renewable generation projects, and to recover all related costs.
- New legislation, litigation or 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 SNF.
- 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 or regulatory proceedings or investigations.
- 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.
- The impact of changing expectations and demands of customers, regulators, investors and stakeholders, including heightened emphasis on environmental, social and governance concerns.
- 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 2022 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.

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

EXECUTIVE OVERVIEW

AEP Consolidated Earnings Attributable to Common Shareholders

Second Quarter of 2023 Compared to Second Quarter of 2022

Earnings Attributable to AEP Common Shareholders decreased from $525 million in 2022 to $521 million in 2023 primarily due to:

- A decrease in weather-related sales volumes.
- An increase in interest expense due to higher interest rates and debt balances.
- Unfavorable mark-to-market economic hedge activity driven by a decrease in commodity prices.
- A gain on the sale of mineral rights in 2022.

These decreases were partially offset by:

- Favorable rate proceedings in AEP's various jurisdictions.
- Investment in transmission assets, which resulted in higher revenues and income.
- A loss related to the expected sale of the Kentucky Operations in 2022. The expected sale was terminated in April 2023.
- An impairment of AEP's equity investment in Flat Ridge 2 in 2022.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

Earnings Attributable to AEP Common Shareholders decreased from $1,239 million in 2022 to $918 million in 2023 primarily due to:

- A decrease in weather-related sales volumes.
- An increase in interest expense due to higher interest rates and debt balances.
- Unfavorable mark-to-market economic hedge activity driven by a decrease in commodity prices.
- A loss related to the expected sale of the competitive contracted renewable portfolio in 2023.
- A gain on the sale of mineral rights in 2022.

These decreases were partially offset by:

- Favorable rate proceedings in AEP's various jurisdictions.
- Investment in transmission assets, which resulted in higher revenues and income.
- A loss related to the expected sale of the Kentucky Operations in 2022. The expected sale was terminated in April 2023.
- An impairment of AEP's equity investment in Flat Ridge 2 in 2022.

See "Results of Operations" section for additional information by operating segment.

Customer Demand

AEP's weather-normalized retail sales volumes for the second quarter of 2023 increased by 1.5% from the second quarter of 2022. Weather-normalized residential sales decreased by 2.4% in the second quarter of 2023 from the second quarter of 2022. This decrease was primarily due to a reduction in usage per customer due to the impacts of inflation, partially offset by an increase in customers. Weather-normalized commercial sales increased by 7.7% in the second quarter of 2023 compared to the second quarter of 2022. The increase in commercial sales was primarily due to new data center loads and economic development. AEP's second quarter 2023 industrial sales volumes increased by 0.1% from the second quarter of 2022.

AEP's weather-normalized retail sales volumes for the six months ended June 30, 2023 increased by 2.4% compared to the six months ended June 30, 2022. Weather-normalized residential sales decreased by 1.8% for the six months ended June 30, 2023 compared to the six months ended June 30, 2022. This decrease was primarily due to a reduction in usage per customer due to the impacts of inflation, partially offset by an increase in customers. Weather-normalized commercial sales increased by 7.8% for the six months ended June 30, 2023 compared to the six months ended June 30, 2022. The increase in commercial sales was primarily due to new data center loads and economic development. AEP's industrial sales volumes for the six months ended June 30, 2023 increased by 2.6% compared to the six months ended June 30, 2022. The increase in industrial sales was spread across many sectors.

Supply Chain Disruption and Inflation

The Registrants have experienced certain supply chain disruptions driven by several factors including 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.

AEP and its utilities finance its operations with commercial paper and other variable rate instruments. AEP generally uses short-term borrowings to fund working capital needs until long-term funding is arranged. Sources of long-term funding includes the issuance of long-term debt. These financing options to maintain adequate liquidity are subject to fluctuations in interest rates. The United States economy has experienced 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. To the extent interest rates continue to increase, it could reduce future net income and cash flows and impact financial condition.

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, services and cost of capital and further extend lead times which could reduce future net income and cash flows and impact financial condition.

Termination of Planned 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. The SPA was subsequently amended in September 2022 to reduce the purchase price to approximately $2.646 billion. The sale required approval from the KPSC and from the FERC under Section 203 of the Federal Power Act. The SPA contained certain termination rights if the closing of the sale did not occur by April 26, 2023.

In May 2022, the KPSC approved the sale of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. In December 2022, the FERC issued an order denying, without prejudice, authorization of the proposed sale stating the applicants failed to demonstrate the proposed transaction will not have an adverse effect on rates. In February 2023, a new filing for approval under Section 203 of the Federal Power Act was submitted. In March 2023, the KPSC and other intervenors made filings recommending the FERC reject AEP and Liberty's new Section 20: application seeking approval of the sale.

In April 2023, AEP, AEPTCo and Liberty entered into a Mutual Termination Agreement (Termination Agreement) terminating the SPA.The parties entered into the Termination Agreement as all of the conditions precedent to closing the sale could not be satisfied prior to April 26, 2023.

The impact of the Termination Agreement did not have a material impact on AEP's statements of income for the three and six months ended June 30, 2023. Upon reverting to a held and used model in the first quarter of 2023, AEP was required to present its investment in the Kentucky Operations at the lower of fair value or historical carrying value which resulted in a $335 million reduction recorded in Property, Plant and Equipment. The reduced investment in KPCo's assets is being amortized over the 30 year average useful life of the KPCo assets.

Planned Disposition of the Competitive Contracted Renewables Portfolio

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. As of June 30, 2023, 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 four joint venture wind farms, totaling $246 million, accounted for as equity method investments.

In late January 2023, AEP received final bids from interested parties. In February 2023, AEP's Board of Directors approved management's plan to sell the competitive contracted renewables portfolio and AEP signed an agreement to sell the competitive contracted renewables portfolio to a nonaffiliated party for $1.5 billion including the assumption of project debt. AEP recorded a pretax loss of $112 million ($88 million after-tax) in the first quarter of 2023 as a result of reaching Held for Sale status. Management concluded the impact of any other than temporary decline in the fair value of the four joint venture wind farms was not material.

AEP expects to close on the sale in the third quarter of 2023, pending approval from the Committee on Foreign Investment in the United StatesAEP expects to receive cash proceeds, net of taxes, transaction fees and other customary closing adjustments, of approximately $1.2 billion. See the "Assets and Liabilities Held for Sale" section of Note 6 for additional information.

Planned Sale of AEP Energy and AEP Onsite Partners

Management has continued a strategic evaluation of the business with a focus on core regulated utility operations, risk mitigation and simplification. As a result of these efforts, the following decisions have recently been made with respect to AEP Energy and AEP Onsite Partners.

AEP Energy

In October 2022, AEP initiated a strategic evaluation for its ownership in AEP Energy, a wholly-owned retail energy supplier that supplies electricity and/or natural gas on a price risk managed basis to residential, commercial and industrial customers. AEP Energy provides various energy solutions in Illinois, Pennsylvania, Delaware, Maryland, New Jersey, Ohio and Washington, D.CAEP Energy had approximately 844,000 customer accounts as of June 30, 2023. In April 2023, management completed the strategic evaluation of AEP Energy and initiated a sale process. The timing of the completion of the sales process is dependent upon a number of factors. AEP is currently targeting the sales process to be completed in the first half of 2024. Depending on the outcome of the sales process, it could reduce future net income and impact financial condition.

AEP Onsite Partners

In April 2023, AEP also made a decision to include AEP Onsite Partners in a sale process.AEP OnSite Partners targets opportunities in distributed solar, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other energy solutions. As of June 30, 2023, AEP OnSite Partners owned projects located in 22 states, including approximately 168 MWs of installed solar capacity, and approximately 27 MWs of solar projects under construction. As of June 30, 2023, the net book value of these assets was $354 million. The timing of the completion of the sales process is dependent upon a number of factors. AEP is currently targeting the sales process to be completed in the first half of 2024.

AEP Onsite Partners also owns a 50% interest in NM Renewable Development, LLC, (NMRD) totaling $106 million accounted for as an equit method investment. The NMRD portfolio consists of 8 operating solar projects totaling 135 MWs, one 50 MW project under construction and 6 projects totaling 440 MWs in development. Separate from the remainder of AEP Onsite Partners, AEP and the joint owner have agreed to initiate a joint sales process for their respective interests in NMRD.The timing of the completion of the sales process is dependent upon a number of factors. AEP is currently targeting the sales process to be completed in the fourth quarter of 2023.

If AEP is unable to recover the net book value or carrying value of these assets as part of the sale process, it could reduce future net income and impact financial condition.

Planned Sale and Strategic Evaluation of Certain Transmission Joint Ventures

In April 2023, AEP also initiated a strategic evaluation for its ownership in certain transmission joint ventures in the AEP Transmission HoldCo segment including Pioneer Transmission, LLC, Prairie Wind Transmission, LLC and Transource EnergyIn July 2023, AEP made a decision to initiate a sales process for its investment in Pioneer Transmission, LLC and Prairie Wind Transmission, LLCAs of June 30, 2023, AEP's investment in Pioneer Transmission, LLC, and Prairie Wind Transmission, LLC was $46 million and $19 million, respectively.

As of June 30, 2023, the net book value of Transource Energy was $278 million inclusive of $38 million related to noncontrolling interest on AEP's balance sheet. Potential alternatives may include continued ownership or a sale. Management has not made a decision regarding the potential alternatives, but expects to complete the strategic evaluation by the end of 2023.

Federal Tax Legislation

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022 or IRA.

In June 2023, the IRS issued temporary regulations related to the transfer of tax credits.AEP and subsidiaries have qualifying tax credits that are eligible to be transferred and, depending on market conditions, will consider selling qualifying tax credits in the second half of 2023. See Note 11 - Income Taxes for additional information.

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.

- *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.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. In December 2022, SWEPCo and the PUCT filed requests for rehearing with the Texas Supreme Court. In June 2023, the Texas Supreme Court denied SWEPCo's request for rehearing and the case was 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 June 30, 2023. 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 SWEPCo is ultimately unable to recover AFUDC in excess of the Texas jurisdictional cost cap, SWEPCo estimates it may be required to make customer refunds ranging from $0 to $195 million related to revenues collected from February 2013 through June 2023 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 had previously plead guilty and, in March 2023, a federal jury convicted Larry Householder and another individual of participating in the racketeering conspiracy. 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 March 2023 and May 2023, certain joint customers submitted a complaint and a formal challenge at the FERC related to the 2022 Annual Update of the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP, respectively. These challenges primarily relate to stand-alone treatment of NOLCs in the transmission formula rates of the AEP transmission owning subsidiaries. AEPSC, on behalf of the AEP transmission owning subsidiaries within PJM and SPP, filed answers to the joint formal challenge and complaint with the FERC in the second quarter of 2023.

The Registrants transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 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 NOLCs for transmission formula rates increased the annual revenue requirements for years 2023, 2022, and 2021 by $60 million, $69 million and $78 million, respectively. Through the second quarter of 2023, the Registrants' financial statements reflect a provision for refund for certain NOLC revenues billed by PJM and SPP. Also, a certain portion of the impact of inclusion of NOLCs 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". If the Registrants are required to make refunds as a result of these challenges, it could reduce future net income and cash flows and impact financial condition.

The Registrants are also transitioning to stand-alone treatment of NOLCs 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. If the Registrants are successful in transitioning to stand-alone treatment of NOLCs, it could have a material, favorable impact on future net income.

- *Securitization Legislation* - In March 2023, Kentucky (Senate Bill 192) and West Virginia (House Bill 3308) both passed legislation that would allow the securitization of certain plant assets. Eligible costs to be securitized in Kentucky include certain retired generation costs with a minimum value of $200 million as well as certain other regulatory assets, including deferred extraordinary storm costs, as long as the cumulative total requested for securitization is at least $275 million. Eligible costs to be securitized in West Virginia include historical, and if deemed appropriate by the commission, projected costs relating to environmental control costs, expanded net energy costs, storm recovery costs and undepreciated generation utility plant balances.

  In April 2023, APCo and WPCo submitted their 2023 annual ENEC filing with the WVPSC proposing two alternatives to increase ENEC rates effective September 1, 2023. One of the alternatives included an option to securitize approximately $1.9 billion of assets. In June 2023, KPCo filed a request with the KPSC requesting to finance, through the issuance of securitization bonds, approximately $471 million of regulatory assets. See Note 4 - Rate Matters for additional information.

  In April 2023, the Virginia General Assembly approved the Governor's proposed changes to House Bill 1777, modifying APCo's earnings review and base rate process, with a biennial earnings review replacing APCo's current triennial earnings review. APCo will submit its first biennial review filing in 2024 using only a 2023 test year. Also included in this approved legislation is the option for APCo to securitize deferred fuel costs.

- *Texas Legislation* - In May 2023, legislation (Senate Bill 1016) was passed in Texas allowing certain financially based employee incentive compensation to be recovered. As a result of this law change, in the second quarter of 2023 AEP Texas and SWEPCo recognized a favorable impact to pretax income of approximately $27 million and $6 million, respectively.

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 2023. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase (in millions)		Approved ROE	New Rates Effective
SWEPCo	Louisiana	$ 21.0	(a)	9.5%	February 2023

(a) See "2020 Louisiana Base Rate Case" section of Note 4 in the 2022 Annual Report for additional information.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase (in millions)		Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE	
PSO	Oklahoma	November 2022	$ 173.0	(a)	10.4%	8.6%-9.5%	
APCo	Virginia	March 2023	213.0		10.6%	9.2%	(b)
KPCo	Kentucky	June 2023	94.0		9.9%	(c)	

(a) Requested revenue requirement increase, net of existing rider revenues and certain incremental renewable facility benefits expected to be provided to customers through riders.

(b) Represents intervenor testimony. Virginia staff testimony is due in the third quarter of 2023.

(c) Intervenor testimony due in the fourth quarter of 2023.

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" section in Note 4 for additional information.If any of these deferred fuel costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Company	Jurisdiction	Traditional FAC Recovery Reset	As of June 30, 2023	As of December 31, 2022	Increase/ (Decrease)
				(in millions)	
APCo	Virginia (a)	Annually	$ 333.5	$ 407.9	$ (74.4)
APCo	West Virginia	Annually	308.5	288.5	20.0
I&M	Indiana	Bi-Annually	5.4	38.1	(32.7)
I&M	Michigan	Annually	12.1	9.0	3.1
PSO	Oklahoma (b)	Annually	285.1	431.5	(146.4)
SWEPCo	Arkansas	Annually	36.8	65.8	(29.0)
SWEPCo	Texas (c)	Tri-Annually	158.7	191.4	(32.7)
KPCo	Kentucky	Monthly	4.0	23.2	(19.2)
WPCo	West Virginia	Annually	256.6	231.1	25.5
		Total	$ 1,400.7	$ 1,686.5	$ (285.8)

(a) Includes $56 million and $223 million as of June 30, 2023 and December 31, 2022, respectively, of noncurrent deferred fuel classified as a Regulatory Asset on APCo's balance sheets.

(b) Includes $106 million and $253 million as of June 30, 2023 and December 31, 2022, respectively, of noncurrent deferred fuel classified as a Regulatory Asset on PSO's balance sheets.

(c) Includes $76 million and $0 million as of June 30, 2023 and December 31, 2022, respectively, of noncurrent deferred fuel classified as a Regulatory Asset on SWEPCo's balance sheets.

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 (the Companies) submitted their 2022 annual ENEC filing with the WVPSC requesting a $297 million annual increas in ENEC revenues, effective September 1, 2022.In February 2023, the WVPSC issued an order stating that the commission will not grant additional rate increases for fuel costs until the WVPSC staff completes its prudency review.In April 2023, the Companies submitted their 2023 annual ENEC filing with the WVPSC, proposing two alternatives to increase ENEC rates effective September 1, 2023The first alternative is a $293 million annual increase in ENEC rates comprised of a $89 million increase for current year ENEC expense and a $200 million annual increase for the recovery of the Companies' February 28, 2023 ENEC under-recovery balances over three years, including debt and equity carrying costs.The second alternative is an $89 million annual increase in ENEC rates with the Companies securitizing approximately $1.9 billion of assets, including $553 million relating to ENEC under-recoveries as of February 28, 2023.Additionally, in April 2023, the Staff submitted the prudency review prepared by an independent consultant retained by the WVPSC staff regarding the Companies' operation of the Amos, Mountaineer and Mitchell coal plants that Staff was directed to conduct by the WVPSC in May 2022 (Consultant's Report)Adoption of the Consultant's Report's findings by the WVPSC could result in a disallowance of up to $285 million. The Companies disagree with the conclusions and recommendations contained in the Consultant's Report and intend to dispute them in the appropriate proceedings before the WVPSC. See "ENEC Filings" section of Note 4 for additional information.

In September 2022, the Director of the Public Utility Division of the OCC approved a Fuel Cost Adjustment 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 October 2022, APCo submitted its annual Virginia fuel factor filing with interim FAC rates effective November 2022. To help mitigate the impact of rising fuel costs on customer bills, APCo proposed recovery of its deferred fuel balance as of October 31, 2022 over two years. In March 2023, the Virginia SCC issued an order approving APCo's request to increase its annual fuel factor by approximately $279 million and APCo's request to recover its October 31, 2022 deferred fuel balance over two years. As ordered by the Virginia SCC, APCo's historical period fuel and purchased power expenses for the years 2019 through 2022 are currently subject to a fuel audit/prudency review. Virginia staff will include the results of this audit in APCo's next annual Virginia fuel factor filing that will be submitted in the fourth quarter of 2023.

In April 2023, the PUCT issued an order approving an interim fuel surcharge, effective February 2023, allowing SWEPCo to recover $83 million of non Sabine and Oxbow mine related fuel costs through June 2024. In June 2023, an unopposed settlement agreement was filed with the PUCT that would allow SWEPCo to recover $81 million of Sabine and Oxbow mine related fuel costs through 2035. A decision from the PUCT on the unopposed settlement agreement is expected in the fourth quarter of 2023. See "Dolet Hills Power Station and Related Fuel Operations" and "Pirkey Plant and Related Fuel Operations" sections in Note 4 for additional information related to the recovery of fuel costs in SWEPCo's Arkansas and Louisiana jurisdictions.

Renewable Generation

The growth of AEP's regulated 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.

Approved Renewable Generation Filings

The Registrants have received regulatory approvals from various state regulatory commissions to acquire approximately 2,204 MWs of owned renewable generation facilities, totaling approximately $5.2 billion, in addition to 73 MWs of renewable purchase power agreements, as included in the following table:

Company	Generation Type	Expected Commercial Operation	Owned/PPA	Generating Capacity
				(in MWs)
APCo	Solar	Q3 2023	Owned	5
APCo	Wind	Q3 2025	Owned	204
PSO	Solar	Q2 2025 through Q4 2025	Owned	443
PSO	Wind	Q2 2025 through Q4 2025	Owned	553
SWEPCo (a)	Solar	Q2 2025 through Q4 2025	Owned/PPA	273
SWEPCo (a)	Wind	Q4 2024 through Q4 2025	Owned	799
Total Approved Renewable Projects				2,277

(a) Includes approvals by the APSC and LPSC for 999 MWs of owned projects. Additionally, the LPSC approved the flex-up option, allowing SWEPCo to recover the portion of the projects denied by the PUCT.

Renewable Generation Filings Pending Regulatory Approval

Recently, the Registrants have made filings with various state regulatory commissions seeking approval to acquire 612 MWs of owned renewable generation facilities, in addition to 484 MWs of renewable purchased power agreements, as included in the following table:

Company	Generation Type	Expected Commercial Operation	Owned/PPA	Generating Capacity
				(in MWs)
APCo	Solar	Q2 2024 through Q1 2026	PPA	204
APCo	Wind	Q4 2025	Owned	143
I&M	Solar	Q4 2025 through Q2 2026	Owned/PPA	749
Total Renewable Projects Pending Regulatory Approval				1,096

Significant Renewable Generation Requests for Proposal (RFP)

As part of AEP's transition to diversify the company's regulated generation resources and build its renewable generation portfolio, the Registrants issue RFPs to identify potential renewable projects. The table below includes RFPs recently issued for owned generation and purchased power generation. These projects would be subject to regulatory approval.

Company	Issuance Date	Projected In-Service Dates	Generation Type	Generating Capacity
				(in MWs)
I&M	March 2023	Year End 2027	Wind (a)	800
I&M	March 2023	Year End 2027	Solar (a)(b)	850
APCo	April 2023	Year End 2026	Wind and/or Solar (c)(d)	800
Total Significant RFPs				2,450

(a) RFP is an all-source solicitation seeking proposals for both owned projects and PPAs from various types of generation including 315 MWs of storage and 540 MWs of natural gas. Includes an option for battery storage.
(b) Includes consideration for 300 MWs of solar paired with up to 60 MWs of battery storage.
(c) Includes RFP for up to 200 MWs of PPAs.
(d) Includes an option for battery storage.

Merchant Portion of Turk Plant

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

Approximately 20% of the Turk Plant output is currently not subject to cost-based rate recovery in Arkansas. This portion of the plant's output is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under retail cost-based rate recovery in Texas, Louisiana and through SWEPCo's wholesale customers under FERC-approved ratesIn November 2022, SWEPCo filed a Certificate of Public Convenience and Necessity with the APSC for approval to operate the Turk plant to serve Arkansas customers and recover the associated costs through a cost recovery rider. Cost-based recovery of the Turk Plant would aid SWEPCo's near-term capacity needs and support compliance with SPP's 2023 increased capacity planning reserve margin requirements. In April 2023, intervenors filed testimony recommending the APSC deny the Certificate of Public Convenience and Necessity on the basis that the Turk Plant is not the least cost alternative.

In June 2023, SWEPCo filed rebuttal testimony with the APSC. In July 2023, additional intervenor testimony was filed with the APSC by the Attorney General of Arkansas and the APSC staff with recommendations consistent with the previously filed April 2023 intervenor testimony. A hearing is scheduled for the third quarter of 2023. As of June 30, 2023, the net book value of the Turk Plant was $1.4 billion, before cost of removal including CWIP and inventory. If SWEPCo cannot ultimately recover its investment and expenses related to the Arkansas retail portion of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

LITIGATION

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

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 U. S. District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. 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 U.S. 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 substantive and forum-based motions to dismiss on April 29, 2022. On September 13, 2022, the New York state court granted the forum-based motion to dismiss with prejudice and the plaintiff subsequently filed a notice of appeal with the New York appellate court. On January 20, 2023, the New York plaintiff filed a motion to intervene in the pending Ohio federal court action and withdrew his appeal in New York. 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 the amended complaint and subsequently filed a brief in opposition to the New York plaintiffs' motion to intervene in the consolidated action in Ohio. On March 20, 2023, the federal district court issued an order granting the motion to dismiss with prejudice and denying the New York plaintiffs' motion to intervene. On April 20, 2023, one of the plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Sixth Circuit of the Ohio federal district court order dismissing the consolidated action and denying the intervention. On June 15, 2022, the Ohio state court entered an order continuing the stays of that case until the final 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 was directed to the Board of Directors of AEP (AEP Board) and contained factual allegations involving HB 6 that were generally consistent with those in the derivative litigation filed in state and federal court. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect. In April 2023, AEP received a litigation demand from counsel representing the purported AEP shareholder who filed the dismissed derivative action in New York state court and unsuccessfully tried to intervene in the consolidated derivative actions in Ohio federal court. The litigation demand letter is directed to the AEP Board 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 certain current and former directors and officers, and that AEP commence a civil action for breaches of fiduciary duty and related claims against any individuals who allegedly harmed AEP. The AEP Board will act in response to the letter as appropriate. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

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 investigation. AEP is cooperating fully with the SEC's investigation, which has included taking testimony from certain individuals and inquiries regarding Empowering Ohio's Economy, Inc., which is a 501(c)(4) social welfare organization, and related disclosures. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this investigation will have a material impact on financial condition, results of operations or cash flows.

Claims for Indemnification Made by Owners of the Gavin Power Station

In November 2022, the Federal EPA issued a final decision denying Gavin Power LLC's requested extension to allow a CCR surface impoundment at the Gavin Power Station to continue to receive CCR and non-CCR waste streams after April 11, 2021 until May 4, 2023 (the Gavin Denial). As part of the Gavin Denial, the Federal EPA made several determinations related to the CCR Rule (see "Coal Combustion Residual (CCR) Rule" section below for additional information), including a determination that the closure of the 300 acre unlined fly ash reservoir (FAR) is noncompliant with the CCR Rule in multiple respects. The Gavin Power Station was formerly owned and operated by AEP and was sold to Gavin Power LLC and Lightstone Generation LLC in 2017. Pursuant to the PSA, AEP maintained responsibility to complete closure of the FAR in accordance with the closure plan approved by the Ohio EPA which was completed in July 2021. The PSA contains indemnification provisions, pursuant to which the owners of the Gavin Power Station have notified AEP they believe they are entitled to indemnification for any damages that may result from these claims, including any future enforcement or litigation resulting from the Federal EPA's determinations of noncompliance with various aspects of the CCR Rule as part of the Gavin Denial. The owners of the Gavin Power Station have also sought indemnification for landowner claims for property damage allegedly caused by modifications to the FAR. Management does not believe that the owners of the Gavin Power Station have any valid claim for indemnity or otherwise against AEP under the PSA. In addition, Gavin Power LLC, several AEP subsidiaries, and other parties have filed Petitions for Review of the Gavin Denial with the U.S. Court of Appeals for the District of Columbia Circuit. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Claims for Damages Related to Sabine Lignite Mining Agreement

In May 2023, North American Coal Corporation (NACC) and Sabine, a subsidiary of NACC, filed suit against SWEPCo in Texas state court for breach of the Lignite Mining Agreement (LMA) between Sabine and SWEPCo. NACC and Sabine assert that the terms of the LMA require SWEPCo to continue operating the Pirkey Plant and obtaining coal from the Sabine mine through 2035 and that SWEPCo has breached the agreement by closing the plant. The complaint seeks both injunctive relief ordering SWEPCo to cease demolition and reclamation activities at the Pirkey Plant and the Sabine mine and damages, which Sabine has asserted are $85 million in lost fees. The parties have entered into a standstill agreement staying both the litigation and certain demolition and reclamation activities at the Pirkey Plant and the Sabine mine. SWEPCo will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

ENVIRONMENTAL ISSUES

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

AEP is engaged in litigation about environmental issues, was notified of potential responsibility for the clean-up of contaminated sites and incurred costs for disposal of SNF and future decommissioning of the nuclear units. Management is engaged in the development of possible future requirements including the items discussed below.

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 an 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 June 30, 2023, the AEP System owned generating capacity of approximately 24,700 MWs, of which approximately 10,700 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.

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.

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 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. In January 2023, the Federal EPA announced its proposed decision to strengthen the primary (health-based) annual PM2.5 standard. The Biden administration has previously indicated that it is likely to revisit the NAAQS for ozone, which were left unchanged by the prior administration following its review.Management cannot currently predict if any changes to either standard are likely to be finalized 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 that the Federal EPA began implementing in 2015, which was designed to address interstate transport of emissions that contribute significantly to non-attainment and interfere with maintenance of the 1997 ozone NAAQS and the 1997 and 2006 PM NAAQS in downwind states. 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 basis. The Federal EPA has revised, or updated, the CSAPR trading programs several times since they were established.

In January 2021, the Federal EPA finalized a revised CSAPR, which substantially reduced the ozone season NO_X budgets for several states, including states where AEP operates, beginning in ozone season 2021. Several utilities and other entities potentially subject to the Federal EPA's NO_X regulations challenged that final rule in the U.S. Court of Appeals for the District of Columbia Circuit and oral argument was held in September 2022. In March 2023, the court rejected the challenge and upheld the rule. Management 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 2023, the Federal EPA Administrator finalized the disapproval of interstate transport SIPs submitted by 19 states addressing the 2015 Ozone NAAQSDisapproval of the SIPs provides the Federal EPA with authority to impose a FIP for those states, replacing the SIPs that were disapprovedVarious legal challenges have been brought by several states, utilities and other industry parties challenging the SIP disapproval. SWEPCo filed a petition for review of the disapproval of the Arkansas SIP in the U.S. Court of Appeals for the Eighth Circuit on April 14, 2023In March 2023, the Federal EPA finalized a FIP that further revises the ozone season NO_X budgets under the existing CSAPR program in states to which the FIP applies.The FIP will take effect August 4, 2023. In May 2023, the U.S. Court of Appeals for the Fifth Circuit stayed the Federal EPA's disapproval of the Texas and Louisiana SIPs pending a decision on the merits of the appeal, calling into question the Federal EPA's ability to enforce the FIP in those states.Since then, federal courts have stayed the denial of state SIPs in five other states.In addition, the U.S. Court of Appeals for the Sixth Circuit issued an administrative stay of the Federal EPA's disapproval of the Kentucky SIP pending the court's disposition of Kentucky's stay motion. In June 2023, the Federal EPA signed an interim final rule staying the applicability of the FIP in six states subject to judicial stays, including Arkansas, Kentucky, Louisiana and Texas, and adjusting certain compliance dates. Management is evaluating the impacts of the FIP and cannot predict the outcome of the litigation.

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 District of Columbia 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 District of Columbia Circuit Court decisions.Oral arguments were held in February 2022 and on June 30, 2022, the United States Supreme Court reversed the District of Columbia Circuit Court's decision and remanded for further proceedings.In May 2023, the Federal EPA proposed greenhouse gas standards and guidelines for new and existing fossil-fuel fired sources. The proposal relies heavily on carbon capture and sequestration and natural gas co-firing as means to reduce CO_2 emissions from coal fired plants and hydrogen co-firing and carbon capture and sequestration to reduce CO_2 emissions from gas turbines. Management is evaluating the proposed rule.

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 (RGGI), 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 early 2022, Virginia's governor issued an executive order directing his administration to end Virginia's participation in RGGI. In June 2023, the Virginia Air Pollution Control Board approved a regulation to withdraw Virginia from RGGI and the governor submitted the regulation to the Virginia Register, meaning that the regulation will be effective at the end of August 2023, if there are no other changes. The withdrawal will be effective on December 31, 2023 although it may be subject to legal challenge.

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 CO_2 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 greenhouse gas (GHG) emissions in 2022 were approximately 52.5 million metric tons CO_2e, approximately a 65% reduction from AEP's 2005 Scope 1 GHG emissions (inclusive of emission reductions that result from plants that have been sold). 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.

Mercury and Air Toxics Standards (MATS) Rule

In April 2023, the Federal EPA issued a proposed rule that would revise the MATS for power plants.The proposed rule includes a more stringent standard for emissions of filterable PM for coal-fired electric generating units, as well as a new mercury standard for lignite-fired electric generating units. The proposed rule also requires the installation and operation of continuous emissions monitors for PM. Management is evaluating the impacts of the rule as proposed and will continue to monitor the rulemaking.

Coal Combustion Residual (CCR) 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	Generating Capacity	Net Book Value (a)		Projected Retirement Date
		(in MWs)	(in millions)		
AEGCo	Rockport Plant	1,310	$ 302.5		2028
APCo	Amos Plant	2,930	2,136.5		2040
APCo	Mountaineer Plant	1,320	970.1		2040
I&M	Rockport Plant	1,310	570.6	(b)	2028
KPCo	Mitchell Plant	780	568.0		2040
SWEPCo	Flint Creek Plant	258	258.6		2038
WPCo	Mitchell Plant	780	668.6		2040

(a) Net book value as of June 30, 2023, before cost of removal including CWIP and inventory.
(b) Amount includes a $135 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 proposed to deny several extension requests filed by the other utilities based on allegations that those utilities are not in compliance with the CCR Rule (the January Actions).In November 2022, the Federal EPA finalized one of these denials.The Federal EPA's allegations of noncompliance rely on new interpretations of the CCR Rule requirements.The January 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.

In July 2022, the Federal EPA proposed conditional approval of the pending extension request for the Mountaineer Plant.The Federal EPA alleged that the Mountaineer Plant was not fully compliant with the CCR Rule.In December 2022, AEP withdrew the pending extension request for the Mountaineer Plant as work to construct new CCR disposal facilities was completed and the extension was no longer needed.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 the context of the proposed and final decisions on extension requests issued to date indicate that there is a risk that the Federal EPA may conclude that AEP is not eligible for an extension of time to cease use of those CCR impoundments for which extension requests are pending and/or that one or more of AEP's facilities is not in compliance with the CCR Rule. If 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.

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.

Under the second option for obtaining an extension of the April 11, 2021 deadline to cease operation of unlined impoundments, a generating facility may 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. In March 2023, the Pirkey Plant was retired. The table below summarizes the net book value of Welsh Plant, Units 1 and 3 as of June 30, 2023.

Company	Plant Name and Unit	Generating Capacity	Net Investment (a)	Accelerated Depreciation Regulatory Asset	Projected Retirement Date
		(in MWs)	(in millions)		
SWEPCo	Welsh Plant, Units 1 and 3	1,053	$ 384.3	$ 105.4	2028 (b)(c)

(a) Net book value including CWIP excluding cost of removal and materials and supplies.
(b) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028.
(c) 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.

In May 2023, the Federal EPA proposed revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities ("legacy CCR surface impoundments") as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land ("CCR management units").Management is still evaluating the impacts the proposed rule would have, if finalized.

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, established additional options for reusing and discharging small volumes of bottom ash transport water, provided an exception for retiring units and extended 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 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. In March

2023, the Federal EPA proposed further revisions to the ELG rule which, if finalized, would establish a zero discharge standard for FGD wastewater and bottom ash transport water, and more stringent discharge limits for combustion residual leachate. Management is evaluating the impacts of the proposed rule to operations. Management cannot predict whether the Federal EPA will actually finalize further revisions, but will continue to monitor this issue and will participate in further rulemaking activities as they arise.

In January 2023, the Federal EPA finalized a new rule revising the definition of "waters of the United States," which became effective in March 2023. The new rule expands the scope of the definition, which means that permits may be necessary where none were previously required and issued permits may need to be reopened to impose additional obligations. A number of legal challenges in courts across the country have resulted in the rule being stayed in more than half of the states. Management is evaluating what impacts the revised rule will have on operations.

In May 2023, the United States Supreme Court issued a decision that significantly narrowed the scope of "waters of the United States," specifically which wetlands can be regulated as waters of the United States. In response, the Biden administration has announced plans to expeditiously issue a new rule defining "waters of the United States" consistent with the court decision. Management will monitor developments related to such rulemaking.

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.

The table below summarizes the net book value, as of June 30, 2023, 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	$ 120.5	$ 154.9		2026		(c)	$ 14.9
SWEPCo	Pirkey Plant	—	111.8	(d)	2023		(e)	—
SWEPCo	Welsh Plant, Units 1 and 3	384.3	105.4		2028	(f)	(g)	38.6

(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) Represents Arkansas and Texas jurisdictional share.
(e) As part of the 2021 Arkansas Base Rate Case, the APSC granted SWEPCo regulatory asset treatment. SWEPCo will request recovery including a weighted average cost of capital carrying charge through a future proceeding. The Texas share of the Pirkey Plant will be addressed in SWEPCo's next base rate case.
(f) In November 2020, management announced it will cease using coal at the Welsh Plant in 2028. Management is evaluating a potential conversion to natural gas after 2028 for both units.
(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.

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 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, 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 tables present Earnings (Loss) Attributable to AEP Common Shareholders by segment:

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(in millions)			
Vertically Integrated Utilities	$ 278.1	$ 301.2	$ 539.1	$ 599.4
Transmission and Distribution Utilities	176.7	164.8	302.4	317.6
AEP Transmission Holdco	196.4	141.8	377.9	314.9
Generation & Marketing	(32.3)	72.6	(190.0)	186.8
Corporate and Other	(97.7)	(155.9)	(111.2)	(179.5)
Earnings Attributable to AEP Common Shareholders	$ 521.2	$ 524.5	$ 918.2	$ 1,239.2

Three Months Ended June 30, 2023	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
	(in millions)			
Revenues	$ 2,674.5	$ 1,340.2	$ 458.6	$ 331.4
Fuel, Purchased Electricity and Other	875.3	279.0	—	327.1
Gross Margin	1,799.2	1,061.2	458.6	4.3
Other Operation and Maintenance	819.1	439.7	33.9	56.2
Depreciation and Amortization	457.1	183.1	98.5	8.2
Taxes Other Than Income Taxes	126.5	159.0	69.7	1.7
Operating Income (Loss)	396.5	279.4	256.5	(61.8)
Other Income	7.1	0.8	3.0	11.7
Allowance for Equity Funds Used During Construction	9.7	8.2	23.1	—
Non-Service Cost Components of Net Periodic Benefit Cost	31.5	14.0	1.5	6.5
Interest Expense	(195.1)	(88.1)	(52.9)	(26.2)
Income (Loss) Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	249.7	214.3	231.2	(69.8)
Income Tax Expense (Benefit)	(28.3)	37.6	55.3	(33.0)
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.4	—	21.4	(1.8)
Net Income (Loss)	278.4	176.7	197.3	(38.6)
Net Income (Loss) Attributable to Noncontrolling Interests	0.3	—	0.9	(6.3)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 278.1	$ 176.7	$ 196.4	$ (32.3)

Three Months Ended June 30, 2022

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
		(in millions)		
Revenues	$ 2,648.5	$ 1,301.6	$ 378.8	$ 659.6
Fuel, Purchased Electricity and Other	837.8	252.7	—	519.8
Gross Margin	1,810.7	1,048.9	378.8	139.8
Other Operation and Maintenance	779.9	441.1	36.2	(6.0)
Gain on Sale of Mineral Rights	—	—	—	(116.3)
Depreciation and Amortization	504.4	187.6	87.9	22.4
Taxes Other Than Income Taxes	128.6	163.8	70.1	3.1
Operating Income	397.8	256.4	184.6	236.6
Other Income	10.7	2.0	0.3	6.8
Allowance for Equity Funds Used During Construction	6.3	7.0	15.3	—
Non-Service Cost Components of Net Periodic Benefit Cost	27.4	11.9	1.2	5.2
Interest Expense	(157.3)	(82.0)	(40.7)	(9.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	284.9	195.3	160.7	239.6
Income Tax Expense (Benefit)	(18.0)	31.3	39.4	(13.5)
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.4	0.8	21.4	(187.2)
Net Income	303.3	164.8	142.7	65.9
Net Income (Loss) Attributable to Noncontrolling Interests	2.1	—	0.9	(6.7)
Earnings Attributable to AEP Common Shareholders	$ 301.2	$ 164.8	$ 141.8	$ 72.6

Six Months Ended June 30, 2023

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
		(in millions)		
Revenues	$ 5,532.3	$ 2,804.4	$ 914.1	$ 658.4
Fuel, Purchased Electricity and Other	1,851.5	671.7	—	709.4
Gross Margin	3,680.8	2,132.7	914.1	(51.0)
Other Operation and Maintenance	1,651.3	931.6	70.6	99.2
Loss on the Expected Sale of the Competitive Contracted Renewable Portfolio	—	—	—	112.0
Depreciation and Amortization	930.6	369.3	196.0	26.4
Taxes Other Than Income Taxes	258.9	337.8	146.5	4.5
Operating Income (Loss)	840.0	494.0	501.0	(293.1)
Other Income	14.3	1.3	4.9	20.7
Allowance for Equity Funds Used During Construction	15.5	17.3	39.5	—
Non-Service Cost Components of Net Periodic Benefit Cost	63.3	28.0	3.1	13.1
Interest Expense	(368.0)	(176.2)	(100.1)	(50.5)
Income (Loss) Before Income Tax Expense (Benefit) and Equity Earnings	565.1	364.4	448.4	(309.8)
Income Tax Expense (Benefit)	25.2	62.0	107.6	(111.1)
Equity Earnings of Unconsolidated Subsidiary	0.7	—	38.9	3.7
Net Income (Loss)	540.6	302.4	379.7	(195.0)
Net Income (Loss) Attributable to Noncontrolling Interests	1.5	—	1.8	(5.0)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 539.1	$ 302.4	$ 377.9	$ (190.0)

Six Months Ended June 30, 2022		Vertically Integrated Utilities		Transmission and Distribution Utilities		AEP Transmission Holdco		Generation & Marketing
				(in millions)				
Revenues	$	5,335.9	$	2,548.4	$	790.2	$	1,278.9
Fuel, Purchased Electricity and Other		1,703.9		485.3		—		967.9
Gross Margin		3,632.0		2,063.1		790.2		311.0
Other Operation and Maintenance		1,549.1		869.6		67.9		26.5
Gain on Sale of Mineral Rights		—		—		—		(116.3)
Depreciation and Amortization		1,004.4		371.2		173.2		45.7
Taxes Other Than Income Taxes		253.8		328.2		137.4		6.2
Operating Income		824.7		494.1		411.7		348.9
Other Income		15.9		2.3		0.4		8.9
Allowance for Equity Funds Used During Construction		14.4		14.3		30.9		—
Non-Service Cost Components of Net Periodic Benefit Cost		55.0		23.8		2.5		10.3
Interest Expense		(308.3)		(156.8)		(79.8)		(14.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)		601.7		377.7		365.7		354.1
Income Tax Expense (Benefit)		(0.1)		60.9		89.8		(20.2)
Equity Earnings (Loss) of Unconsolidated Subsidiary		0.7		0.8		40.5		(192.4)
Net Income		602.5		317.6		316.4		181.9
Net Income (Loss) Attributable to Noncontrolling Interests		3.1		—		1.5		(4.9)
Earnings Attributable to AEP Common Shareholders	$	599.4	$	317.6	$	314.9	$	186.8

VERTICALLY INTEGRATED UTILITIES

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in millions of KWhs)			
Retail:				
Residential	6,332	7,039	14,431	16,264
Commercial	5,723	5,911	11,095	11,429
Industrial	8,660	8,906	16,955	17,068
Miscellaneous	545	578	1,066	1,122
Total Retail	21,260	22,434	43,547	45,883
Wholesale (a)	3,484	3,660	6,744	8,134
Total KWhs	24,744	26,094	50,291	54,017

(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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in degree days)			
Eastern Region				
Actual – Heating (a)	122	152	1,253	1,742
Normal – Heating (b)	139	140	1,747	1,744
Actual – Cooling (c)	214	393	219	395
Normal – Cooling (b)	340	333	344	337
Western Region				
Actual – Heating (a)	20	15	657	930
Normal – Heating (b)	35	35	916	906
Actual – Cooling (c)	744	885	802	905
Normal – Cooling (b)	704	693	732	721

(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.

Vertically Integrated Utilities
Reconciliation of 2022 to 2023 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2022 Earnings Attributable to AEP Common Shareholders	$ 301.2	$ 599.4
Changes in Gross Margin:		
Retail Margins	(20.0)	16.5
Margins from Off-system Sales	20.6	47.1
Transmission Revenues	(10.6)	(6.1)
Other Revenues	(1.5)	(8.7)
Total Change in Gross Margin	(11.5)	48.8
Changes in Expenses and Other:		
Other Operation and Maintenance	(39.2)	(102.2)
Depreciation and Amortization	47.3	73.8
Taxes Other Than Income Taxes	2.1	(5.1)
Other Income	(3.6)	(1.6)
Allowance for Equity Funds Used During Construction	3.4	1.1
Non-Service Cost Components of Net Periodic Pension Cost	4.1	8.3
Interest Expense	(37.8)	(59.7)
Total Change in Expenses and Other	(23.7)	(85.4)
Income Tax Expense	10.3	(25.3)
Net Income Attributable to Noncontrolling Interests	1.8	1.6
2023 Earnings Attributable to AEP Common Shareholders	$ 278.1	$ 539.1

Second Quarter of 2023 Compared to Second Quarter of 2022

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

- **Retail Margins** decreased $20 million primarily due to the following:
  - A $55 million decrease in weather-related usage primarily in the residential class.

  This decrease was partially offset by:
  - A $14 million increase at APCo due to a base rate increase in Virginia implemented in October 2022 following the Virginia Supreme Court remand. This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $14 million increase at SWEPCo due to base rate revenue increases in Arkansas and Louisiana and rider increases in all retail jurisdictions. These increases were partially offset in other expense items below.
  - A $12 million increase due to lower customer refunds related to Tax Reform. This increase was offset in Income Tax Expense below.
- **Margins from Off-system Sales** increased $21 million primarily due to Rockport Plant, Unit 2 merchant operations activity.
- **Transmission Revenues** decreased $11 million primarily due to transmission formula rate true-up activity.

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

- **Other Operation and Maintenance** expenses increased $39 million primarily due to the following:
  - A $14 million increase at APCo due to gains from the sale of land in 2022.
  - A $10 million increase in accounts receivable factoring expenses primarily due to increased interest rates.
  - A $9 million increase in generation expenses primarily due to plant outages and maintenance at I&M.
- **Depreciation and Amortization** expenses decreased $47 million primarily due to a $55 million decrease at AEGCo and I&M primarily due to the expiration of the Rockport Plant, Unit 2 lease in December 2022, partially offset by an increase in depreciation expense due to the acquisition of Rockport Plant, Unit 2 at the end of the lease.
- **Interest Expense** increased $38 million primarily due to higher long-term debt balances and interest rates primarily at APCo, I&M, KPCo, PSO and WPCo.
- **Income Tax Benefit** increased $10 million primarily due to the following:
  - A $15 million increase in PTCs. This increase was partially offset in Retail Margins above.
  - A $7 million increase due to a decrease in pretax book income.

  These increases were partially offset by:
  - An $8 million decrease in amortization of Excess ADIT. This decrease was partially offset in Retail Margins above.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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 $17 million primarily due to the following:
  - A $36 million increase at SWEPCo primarily due to a base rate revenue increase in Arkansas and Louisiana and rider increases in all retail jurisdictions. These increases were partially offset in other expense items below.
  - A $34 million increase in weather-normalized retail margins primarily in the residential and commercial classes.
  - A $29 million increase at APCo due to a base rate increase in Virginia implemented in October 2022 following the Virginia Supreme Court remand. This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $26 million increase due to lower customer refunds related to Tax Reform. This increase was offset in Income Tax Expense below.
  - A $21 million increase at I&M due to a reduction in provision for refund partially offset by lower wholesale true-ups.
  - An $18 million increase at PSO in base rate and rider revenues. This increase was partially offset in other expense items below.

  These increases were partially offset by:
  - A $138 million decrease in weather-related usage primarily in the residential class.
- **Margins from Off-system Sales** increased $47 million primarily due to Rockport Plant, Unit 2 merchant operations activity and estimated PJM performance incentives for Rockport Plant, Unit 2 merchant operations related to winter storm Elliott in December 2022.
- **Transmission Revenues** decreased $6 million primarily due to transmission formula rate true-up activity.
- **Other Revenues** decreased $9 million primarily due to the following:
  - A $4 million decrease at APCo primarily due to pole attachment revenue.
  - A $4 million decrease at I&M due to the sale of allowances. This decrease was partially offset in Retail Margins above.

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 $27 million increase in generation expenses primarily due to plant outages and maintenance at I&M.
  - A $20 million increase in accounts receivable factoring expenses primarily due to increased interest rates.
  - An $18 million increase in storm expenses primarily due to major storms at APCo and system restoration primarily at I&M and SWEPCo.
  - A $14 million increase at APCo due to gains from the sale of land in 2022.
  - A $14 million increase at APCo due to the amortization of the regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to under-earnings during the 2017-2019 Triennial Review. This increase was offset in Retail Margins above.
  - An $11 million increase in distribution expenses.
  - A $9 million increase at I&M due to a decreased Nuclear Electric Insurance Limited distribution in 2023.

  These increases were partially offset by:
  - A $29 million decrease in employee-related expenses.
- **Depreciation and Amortization** expenses decreased $74 million primarily due to a $93 million decrease at AEGCo and I&M primarily due to the expiration of the Rockport Plant, Unit 2 lease in December 2022, partially offset by an increase in depreciation expense due to the acquisition of Rockport Plant, Unit 2 at the end of the lease.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $8 million primarily due to additional loss amortization as the result of unfavorable asset returns during 2022, higher interest costs due to higher discount rates and the expiration of prior service credits from previous plan changes.
- **Interest Expense** increased $60 million primarily due to higher long-term debt balances and interest rates primarily at APCo, I&M, KPCo, PSO and WPCo.
- **Income Tax Expense** increased $25 million primarily due to the following:
  - A $35 million decrease in amortization of Excess ADIT. This decrease was partially offset in Retail Margins above.

  This increase was partially offset by:
  - A $13 million increase in PTCs. This increase was partially offset in Retail Margins above.

TRANSMISSION AND DISTRIBUTION UTILITIES

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in millions of KWhs)			
Retail:				
Residential	5,910	6,589	12,176	13,566
Commercial	7,393	6,941	14,137	12,940
Industrial	6,673	6,647	13,199	12,577
Miscellaneous	177	197	345	368
Total Retail (a)	20,153	20,374	39,857	39,451
Wholesale (b)	428	565	881	1,136
Total KWhs	20,581	20,939	40,738	40,587

(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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in degree days)			
Eastern Region				
Actual – Heating (a)	177	206	1,521	2,070
Normal – Heating (b)	185	186	2,076	2,072
Actual – Cooling (c)	184	359	184	360
Normal – Cooling (b)	305	298	308	301
Western Region				
Actual – Heating (a)	2	—	143	278
Normal – Heating (b)	3	3	197	193
Actual – Cooling (d)	955	1,135	1,226	1,223
Normal – Cooling (b)	940	925	1,067	1,051

(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.

Transmission and Distribution Utilities
Reconciliation of 2022 to 2023 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2022 Earnings Attributable to AEP Common Shareholders	$ 164.8	$ 317.6
Changes in Gross Margin:		
Retail Margins	(23.2)	(1.2)
Margins from Off-system Sales	17.3	41.4
Transmission Revenues	21.4	33.7
Other Revenues	(3.2)	(4.3)
Total Change in Gross Margin	12.3	69.6
Changes in Expenses and Other:		
Other Operation and Maintenance	1.4	(62.0)
Depreciation and Amortization	4.5	1.9
Taxes Other Than Income Taxes	4.8	(9.6)
Other Income	(1.2)	(1.0)
Allowance for Equity Funds Used During Construction	1.2	3.0
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	4.2
Interest Expense	(6.1)	(19.4)
Total Change in Expenses and Other	6.7	(82.9)
Income Tax Expense	(6.3)	(1.1)
Equity Earnings of Unconsolidated Subsidiary	(0.8)	(0.8)
2023 Earnings Attributable to AEP Common Shareholders	$ 176.7	$ 302.4

Second Quarter of 2023 Compared to Second Quarter of 2022

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

- **Retail Margins** decreased $23 million primarily due to the following:
  - A $21 million decrease in weather-related usage primarily due to a 49% and 16% decrease in cooling degree days in Ohio and Texas, respectively.
  - A $19 million decrease in revenue from rate riders primarily due to a historical period over recovery in Texas. This decrease was partially offset in Other Operations and Maintenance expenses below.
  - An $18 million decrease in weather-normalized revenues in all retail classes.

  These decreases were partially offset by:
  - A $19 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses in Ohio.This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $14 million increase due to various rider revenues in Ohio. This increase was partially offset in Margins from Off-system Sales and other expense items below.
- **Margins from Off-system Sales** increased $17 million primarily due to the following:
  - A $51 million increase in deferrals of OVEC costs. This increase was offset in Retail Margins above.

This increase was partially offset by:
  - A $33 million decrease in off-system sales at OVEC due to lower market prices and volume.This decrease was offset in Retail Margins above.

- **Transmission Revenues** increased $21 million primarily due to the following:
  - A $14 million increase due to increased load in Texas.
  - A $6 million increase in interim rates driven by increased transmission investments in Texas.

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 $28 million decrease due to legislation passed in Texas in May 2023 allowing employee financially based incentives to be recovered.
  - An $18 million decrease in ERCOT transmission expenses. This increase was offset in Retail Margins above.
  - A $5 million decrease in employee-related expenses in Ohio.

  These decreases were partially offset by:
  - A $19 million increase related to an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.
  - An $18 million increase in Ohio transmission expenses primarily due to:
    - A $15 million increase in transmission formula rate true-up activity.
    - A $12 million increase in recoverable PJM expense. This increase was offset in Retail Margins above.

    These increases were partially offset by:
    - A $6 million decrease in vegetation management expenses in Ohio.
  - A $6 million increase in recoverable distribution expenses primarily related to vegetation management in Ohio. This increase was offset in Retail Margins above.
- **Depreciation and Amortization** expenses decreased $5 million primarily due to the following:
  - A $13 million decrease in recoverable Distribution Investment Rider depreciable expenses in Ohio.This decrease was offset in Retail Margins above.

  This decrease was partially offset by:
  - An $8 million increase in depreciation expense primarily due to an increase in depreciable base in Ohio.
- **Interest Expense** increased $6 million primarily due to higher long-term debt balances and higher interest rates in Texas.
- **Income Tax Expense** increased $6 million primarily due to an increase in pretax book income in Texas.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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

- **Retail Margins** decreased $1 million primarily due to the following:
  - A $46 million decrease in weather-related usage due to a 26% and 49% decrease in heating degree days in Ohio and Texas, respectively, and a 49% decrease in cooling degree days in Ohio.
  - A $24 million decrease in weather-normalized revenues in all retail classes in Texas.

  These decreases were partially offset by:
  - A $43 million increase due 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 $34 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.
- **Margins from Off-system Sales** increased $41 million primarily due to the following:
  - An $84 million increase in deferrals of OVEC costs. This increase was offset in Retail Margins above.

  This increase was partially offset by:
  - A $43 million decrease in off-system sales at OVEC due to lower market prices and volume.This decrease was offset in Retail Margins above and Other Revenues below.
- **Transmission Revenues** increased $34 million primarily due to the following:
  - An $18 million increase in interim rates driven by increased transmission investments in Texas.
  - A $14 million increase due to increased load in Texas.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $62 million primarily due to the following:
  - A $48 million increase related to an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.
  - A $23 million increase in transmission expenses in Ohio primarily due to:
    - A $17 million increase in recoverable PJM expenses. This increase was offset in Retail Margins above.
    - A $16 million increase in transmission formula rate true-up activity.

    These increases were partially offset by:
    - A $7 million decrease in vegetation management expenses in Ohio.
  - An $11 million increase in distribution-related expenses in Texas.
  - An $8 million increase in recoverable distribution expenses related to vegetation management in Ohio. This increase was offset in Retail Margins above.

  These increases were partially offset by:
  - A $28 million decrease due to legislation passed in Texas in May 2023 allowing employee financially based incentives to be recovered.
  - A $14 million decrease in employee-related expenses.
  - A $4 million decrease in ERCOT transmission expenses in Texas. This increase was offset in Retail Revenues above.
- **Depreciation and Amortization** expenses decreased $2 million primarily due to the following:
  - A $21 million decrease in recoverable Distribution Investment Rider depreciable expenses in Ohio.This decrease was offset in Retail Margins above.

  This decrease was partially offset by:
  - A $13 million increase in depreciation expense primarily due to an increase in depreciable base in Ohio.
- **Taxes Other Than Income Taxes** increased $10 million primarily due to higher property taxes driven by increased distribution and transmission investment in Texas.
- **Interest Expense** increased $19 million primarily due to higher long-term debt balances and higher interest rates in Texas.

AEP TRANSMISSION HOLDCO

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	June 30, 2023	June 30, 2022
	(in millions)	
Plant in Service	$ 13,674.6	$ 12,234.0
Construction Work in Progress	2,049.0	1,794.6
Accumulated Depreciation and Amortization	1,189.3	933.1
Total Transmission Property, Net	$ 14,534.3	$ 13,095.5

AEP Transmission Holdco
Reconciliation of 2022 to 2023 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2022 Earnings Attributable to AEP Common Shareholders	$ 141.8	$ 314.9
Changes in Transmission Revenues:		
Transmission Revenues	79.8	123.9
Total Change in Transmission Revenues	79.8	123.9
Changes in Expenses and Other:		
Other Operation and Maintenance	2.3	(2.7)
Depreciation and Amortization	(10.6)	(22.8)
Taxes Other Than Income Taxes	0.4	(9.1)
Interest and Investment Income	2.7	4.5
Allowance for Equity Funds Used During Construction	7.8	8.6
Non-Service Cost Components of Net Periodic Pension Cost	0.3	0.6
Interest Expense	(12.2)	(20.3)
Total Change in Expenses and Other	(9.3)	(41.2)
Income Tax Expense	(15.9)	(17.8)
Equity Earnings of Unconsolidated Subsidiary	—	(1.6)
Net Income Attributable to Noncontrolling Interests	—	(0.3)
2023 Earnings Attributable to AEP Common Shareholders	$ 196.4	$ 377.9

Second Quarter of 2023 Compared to Second Quarter of 2022

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

- **Transmission Revenues** increased $80 million primarily due to the following:
  - A $41 million increase due to continued investment in transmission assets.
  - A $33 million increase due to affiliated transmission formula rate true-up activity. This increase was offset in Other Operation and Maintenance expense across the other Registrant Subsidiaries.
  - A $6 million increase due to nonaffiliated transmission formula rate true-up activity.

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

- **Depreciation and Amortization** expenses increased $11 million primarily due to a higher depreciable base.
- **Allowance for Equity Funds Used During Construction** increased $8 million primarily due to higher AFUDC rates and CWIP.
- **Interest Expense** increased $12 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $16 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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

- **Transmission Revenues** increased $124 million primarily due to the following:
  - An $85 million increase due to continued investment in transmission assets.
  - A $33 million increase due to affiliated transmission formula rate true-up activity. This increase was offset in Other Operation and Maintenance expense across the other Registrant Subsidiaries.
  - A $6 million increase due to nonaffiliated transmission formula rate true-up activity.

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

- **Depreciation and Amortization** expenses increased $23 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $9 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $9 million primarily due to higher AFUDC rates and CWIP.
- **Interest Expense** increased $20 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $18 million primarily due to an increase in pretax book income.

GENERATION & MARKETING

Generation & Marketing
Reconciliation of 2022 to 2023 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2022 Earnings Attributable to AEP Common Shareholders	$ 72.6	$ 186.8
Changes in Gross Margin:		
Merchant Generation	(4.6)	(4.5)
Renewable Generation	(6.8)	(8.6)
Retail, Trading and Marketing	(124.1)	(348.9)
Total Change in Gross Margin	(135.5)	(362.0)
Changes in Expenses and Other:		
Other Operation and Maintenance	(62.2)	(72.7)
Loss on the Expected Sale of the Competitive Contracted Renewable Portfolio	—	(112.0)
Gain on Sale of Mineral Rights	(116.3)	(116.3)
Depreciation and Amortization	14.2	19.3
Taxes Other Than Income Taxes	1.4	1.7
Interest and Investment Income	4.9	11.8
Non-Service Cost Components of Net Periodic Benefit Cost	1.3	2.8
Interest Expense	(17.2)	(36.5)
Total Change in Expenses and Other	(173.9)	(301.9)
Income Tax Benefit	19.5	90.9
Equity Earnings (Loss) of Unconsolidated Subsidiaries	185.4	196.1
Net Loss Attributable to Noncontrolling Interests	(0.4)	0.1
2023 Earnings Attributable to AEP Common Shareholders	$ (32.3)	$ (190.0)

Second Quarter of 2023 Compared to Second Quarter of 2022

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:

- **Renewable Generation** decreased $7 million primarily due to lower production in 2023.
- **Retail, Trading and Marketing** decreased $124 million primarily due to a $125 million unrealized loss on economic hedge activity in 2023 and a $46 million unrealized gain on economic hedge activity in 2022 driven by changes in 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 increased $62 million primarily due to a decrease in land sales and a prior year sale of renewable development projects.
- **Gain on Sale of Mineral Rights** decreased $116 million due to the prior year sale of mineral rights.
- **Depreciation and Amortization** decreased $14 million primarily due to the ceasing of depreciation on the competitive contracted renewable portfolio assets as a result of held for sale classification in 2023.
- **Interest Expense** increased $17 million due to higher interest rates in 2023.
- **Income Tax Benefit** increased $20 million primarily due to a decrease in pretax book income, partially offset by a decrease in PTCs.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** increased $185 million primarily due to the prior year impairment of AEP's investment in Flat Ridge 2 Wind LLC.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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:

- **Renewable Generation** decreased $9 million primarily due to lower production in 2023.
- **Retail, Trading and Marketing** decreased $349 million primarily due to a $269 million unrealized loss on economic hedge activity in 2023 and a $172 million unrealized gain on economic hedge activity in 2022 driven by changes in 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 increased $73 million primarily due to a decrease in land sales and a prior year sale of renewable development projects.
- **Loss on the Expected Sale of the Competitive Contracted Renewable Portfolio** increased $112 million due to the pretax loss on the expected sale recorded in 2023.
- **Gain on Sale of Mineral Rights** decreased $116 million due to the prior year sale of mineral rights.
- **Depreciation and Amortization** expenses decreased $19 million primarily due to the ceasing of depreciation on the competitive contracted renewable portfolio assets as a result of held for sale classification in 2023.
- **Interest and Investment Income** increased $12 million primarily due to higher interest rates on advances to affiliates.
- **Interest Expense** increased $37 million due to higher interest rates in 2023.
- **Income Tax Benefit** increased $91 million primarily due to a decrease in pretax book income partially offset by a decrease in PTCs.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** increased $196 million primarily due to the prior year impairment of AEP's investment in Flat Ridge 2 Wind LLC.

CORPORATE AND OTHER

Second Quarter of 2023 Compared to Second Quarter of 2022

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $156 million in 2022 to a loss of $98 million in 2023 primarily due to:

- A $69 million pretax loss in 2022 related to the termination of the sale of the Kentucky Operations.
- A $34 million increase in interest income, primarily due to higher interest income from affiliates.
- An $18 million decrease in Income Tax Expense primarily due to a $12 million increase in favorable consolidating tax adjustments in 2023 and unfavorable discrete adjustments of $7 million in 2022.
- A $16 million decrease in corporate expenses.
- A $14 million increase due to unrealized losses on AEP's investment in ChargePoint in 2022. As of August 2022, AEP no longer has a direct investment in ChargePoint.

These items were partially offset by:

- A $97 million increase in interest expense due to higher interest rates and an increase in short-term and long-term debt balances.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $180 million in 2022 to a loss of $111 million in 2023 primarily due to:

- A $78 million increase in interest income, primarily due to higher interest income from affiliates.
- A $69 million pretax loss in 2022 related to the termination of the sale of the Kentucky Operations.
- A $51 million decrease in corporate expenses, primarily due to adjustments driven by the termination of the sale of Kentucky Operations.
- A $28 million increase at EIS, primarily due to higher returns on investments.
- A $21 million decrease in Income Tax Expense primarily due to a favorable discrete adjustment of $12 million related to Kentucky Operations outside basis in 2023, $6 million of unfavorable discrete adjustments in 2022 and a $5 million increase in favorable consolidating tax adjustments in 2023.
- A $12 million increase due to unrealized losses on AEP's investment in ChargePoint in 2022. As of August 2022, AEP no longer has a direct investment in ChargePoint.

These items were partially offset by:

- A $187 million increase in interest expense due to higher interest rates on short-term debt and higher long-term debt balances.

AEP SYSTEM INCOME TAXES

Second Quarter of 2023 Compared to Second Quarter of 2022

Income Tax Expense decreased $25 million primarily due to:

- A $21 million increase in PTCs.
- A $7 million decrease due to a decrease in pretax book income.
  These decreases were partially offset by:
- A $7 million increase due to a decrease in amortization of Excess ADIT.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

Income Tax Expense decreased $68 million primarily due to:

- An $83 million decrease due to a decrease in pretax book income.
- A $12 million decrease due to a discrete adjustment related to Kentucky Operations outside basis in 2023.
  These decreases were partially offset by:
- A $32 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

	June 30, 2023		December 31, 2022	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 40,142.3	58.9 %	$ 36,801.0	56.6 %
Short-term Debt	3,867.6	5.7	4,112.2	6.3
Total Debt	44,009.9	64.6	40,913.2	62.9
AEP Common Equity	23,901.4	35.1	23,893.4	36.7
Noncontrolling Interests	222.2	0.3	229.0	0.4
Total Debt and Equity Capitalization	$ 68,133.5	100.0 %	$ 65,035.6	100.0 %

AEP's ratio of debt-to-total capital increased from 62.9% as of December 31, 2022 to 64.6% as of June 30, 2023 primarily due to an increase in debt to support distribution, transmission and renewable investment growth in addition to working capital needs.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity. As of June 30, 2023, 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, long-term asset securitizations, 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. Market volatility and reduced liquidity in the financial markets could affect AEP's ability to raise capital on reasonable terms to fund capital needs, including construction costs and refinancing maturing indebtedness. AEP is also monitoring the current bank environment and any impacts thereof. AEP was not materially impacted by these conditions during the six months ended June 30, 2023. AEP continues to address the cash flow implications of increased fuel and purchased power costs, see "Deferred Fuel Costs" section of Executive Overview for additional information.In February 2023, AEP entered into a $500 million term loan to address short-term liquidity needs.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of June 30, 2023, available liquidity was approximately $3.1 billion as illustrated in the table below:

	Amount	Maturity
Commercial Paper Backup:	(in millions)	
Revolving Credit Facility	$ 4,000.0	March 2027
Revolving Credit Facility	1,000.0	March 2025
Cash and Cash Equivalents	304.9	
Total Liquidity Sources	5,304.9	
Less: AEP Commercial Paper Outstanding	2,238.7	
Net Available Liquidity	$ 3,066.2	

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 six months of 2023 was $3.2 billion. The weighted-average interest rate for AEP's commercial paper during 2023 was 5.21%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of June 30, 2023 was $289 million with maturities ranging from July 2023 to June 2024.

Securitized Accounts Receivables

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and includes a $125 million and a $625 million facility, both of which expire in September 2024. As of June 30, 2023, the affiliated utility subsidiaries were 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 June 30, 2023, this contractually-defined percentage was 61.8%. 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 six months ended June 30, 2023. As of June 30, 2023, 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 August 2023. The proceeds were used to support AEP's overall capital expenditure plans. In June

2023, AEP successfully remarketed the Junior Subordinated Notes on behalf of holders of the corporate units. AEP did not receive any proceeds from the remarketing which were used to purchase a portfolio of treasury securities maturing on August 14, 2023. On August 15, 2023, the proceeds from the maturing treasury portfolio, currently held by the collateral agent, will be used to settle the forward equity purchase contract entered into as part of the Equity Units transaction. The interest rate on the Junior Subordinated Notes was reset to 5.699% with the maturity remaining in 2025. 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 July 2023.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.

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 556.5	$ 451.4
Net Cash Flows from Operating Activities	1,881.6	2,990.7
Net Cash Flows Used for Investing Activities	(4,265.5)	(4,199.0)
Net Cash Flows from Financing Activities	2,178.1	1,378.1
Net Increase (Decrease) in Cash and Cash Equivalents	(205.8)	169.8
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 350.7	$ 621.2

Operating Activities

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(in millions)	
Net Income	$ 916.5	$ 1,238.9
Non-Cash Adjustments to Net Income (a)	1,692.6	1,694.8
Mark-to-Market of Risk Management Contracts	(124.7)	431.4
Property Taxes	202.7	191.6
Deferred Fuel Over/Under-Recovery, Net	342.5	(599.5)
Change in Other Noncurrent Assets	(375.5)	(49.3)
Change in Other Noncurrent Liabilities	(55.4)	144.5
Change in Certain Components of Working Capital	(717.1)	(61.7)
Net Cash Flows from Operating Activities	$ 1,881.6	$ 2,990.7

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Deferred Income Taxes, Loss on the Expected Sale of the Competitive Contracted Renewable Portfolio, Loss on the Expected Sale of the Kentucky Operations, Impairment of Equity Method Investment, AFUDC and Gain on Sale of Mineral Rights.

Net Cash Flows from Operating Activities decreased by $1.1 billion primarily due to the following:

- A $655 million decrease in cash from the Change in Certain Components of Working Capital. The decrease is primarily due to the timing of accounts payable and property tax payments, increases in fuel, material and supplies driven by coal inventory on hand as a result of the mild current year weather and a decrease in margin deposits held due to unfavorable current year pricing variances. These decreases were partially offset by the timing of accounts receivable collections.
- A $556 million decrease primarily due to a reduction in collateral held associated with risk management contracts driven by the reduction in commodity prices.
- A $526 million decrease in cash from Changes in Other Noncurrent Assets and Liabilities. This decrease is primarily due to changes in regulatory assets and liabilities driven by timing differences between collections from and refunds to customers under rate rider mechanisms.
- A $325 million decrease in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.

These decreases in cash were partially offset by:

- A $942 million increase in cash primarily due to the timing of fuel and purchase power revenues and expenses. See the "Deferred Fuel Costs" section of Executive Overview for additional information.

Investing Activities

	Six Months Ended June 30,	
	2023	2022
	(in millions)	
Construction Expenditures	$ (4,049.7)	$ (3,138.1)
Acquisitions of Nuclear Fuel	(73.9)	(67.7)
Acquisitions of Renewable Energy Facilities	(145.7)	(1,207.3)
Proceeds from Sale of Assets	1.0	208.5
Other	2.8	5.6
Net Cash Flows Used for Investing Activities	$ (4,265.5)	$ (4,199.0)

Net Cash Flows Used for Investing Activities increased by $67 million primarily due to the following:

- A $912 million increase in Construction Expenditures, primarily due to increases in Vertically Integrated Utilities of $414 million, Transmission and Distribution Utilities of $358 million and AEP Transmission Holdco of $157 million.
- A $208 million decrease in Proceeds from Sale of Assets, primarily due to the sale of certain mineral rights in 2022. See "Dispositions" section of Note 6 for additional information.

These increases in cash used were partially offset by:

- A $1.1 billion decrease due to the 2022 acquisition of Traverse, partially offset by the 2023 acquisition of the Rock Falls Wind Facility. See "Acquisitions" section of Note 6 for additional information.

Financing Activities

	Six Months Ended June 30,	
	2023	2022
	(in millions)	
Issuance of Common Stock	$ 77.6	$ 812.7
Issuance/Retirement of Debt, Net	3,072.5	1,572.7
Dividends Paid on Common Stock	(863.6)	(803.5)
Other	(108.4)	(203.8)
Net Cash Flows from Financing Activities	$ 2,178.1	$ 1,378.1

Net Cash Flows from Financing Activities increased by $800 million primarily due to the following:

- A $1.3 billion increase in issuances of long-term debt. See Note 12 - Financing Activities for additional information.
- A $239 million increase due to changes in short-term debt. See Note 12 - Financing Activities for additional information.

These increases in cash were partially offset by:

- A $735 million decrease in issuances of common stock primarily due to the prior year settlement of the 2019 equity units.

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 June 30, 2023 through July 27, 2023, the date that the second quarter 10-Q was filed.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $6.8 billion of capital expenditures in 2023. For the four year period, 2024 through 2027, 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 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 2022 Annual Report.

SIGNIFICANT CASH REQUIREMENTS

A summary of significant cash requirements is included in the 2022 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 2022 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 Chief Financial Officer, Chief Commercial Officer, Executive Vice President Utilities, Senior Vice President of Regulated Commercial Operations, Senior Vice President of Treasury and Risk and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer, Chief Commercial Officer, Senior Vice President of Treasury and Risk, Senior Vice President of Competitive Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2022:

MTM Risk Management Contract Net Assets (Liabilities)
Six Months Ended June 30, 2023

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2022	$ 134.7	$ (40.0)	$ 360.5	$ 455.2
(Gain)/Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(145.5)	0.5	(112.4)	(257.4)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	1.5	1.5
Changes in Fair Value Due to Market Fluctuations During the Period (b)	11.7	—	(198.2)	(186.5)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	140.6	(15.4)	—	125.2
Total MTM Risk Management Contract Net Assets (Liabilities) as of June 30, 2023	$ 141.5	$ (54.9)	$ 51.4	138.0
Commodity Cash Flow Hedge Contracts				119.0
Fair Value Hedge Contracts				(124.7)
Collateral Deposits				(37.5)
Total MTM Derivative Contract Net Assets as of June 30, 2023				$ 94.8

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

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 June 30, 2023, credit exposure net of collateral to sub investment grade counterparties was approximately 0.4%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss).

As of June 30, 2023, 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	$ 396.9	$ 72.5	$ 324.4	3	$ 142.2
Split Rating	32.7	—	32.7	1	32.7
No External Ratings:					
Internal Investment Grade	40.4	—	40.4	3	25.1
Internal Noninvestment Grade	2.3	0.7	1.6	3	1.6
Total as of June 30, 2023	$ 472.3	$ 73.2	$ 399.1		

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 June 30, 2023, 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

Six Months Ended June 30, 2023				Twelve Months Ended December 31, 2022			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.2	$ 0.9	$ 0.3	$ 0.1	$ 0.5	$ 4.5	$ 0.7	$ 0.1

VaR Model
Non-Trading Portfolio

Six Months Ended June 30, 2023				Twelve Months Ended December 31, 2022			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 25.0	$ 32.7	$ 15.2	$ 6.1	$ 17.7	$ 76.9	$ 24.7	$ 6.7

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. Prior to 2022, interest rates remained at low levels and the Federal Reserve maintained the federal funds target range at 0.0% to 0.25% for much of 2021. However, during 2022, the Federal Reserve approved several rate increases for a cumulative total of a 4.25% increase. In the first six months of 2023, the Federal Reserve approved another three rate increases for a cumulative total of a 0.75% rate increase and further increases in interest rates may be authorized during 2023. 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 six months ended June 30, 2023 and 2022, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $53 million and $38 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
REVENUES				
Vertically Integrated Utilities	$ 2,629.0	$ 2,595.0	$ 5,445.3	$ 5,241.8
Transmission and Distribution Utilities	1,330.8	1,296.8	2,786.1	2,539.0
Generation & Marketing	318.2	654.4	645.1	1,263.9
Other Revenues	94.5	93.5	186.9	187.6
TOTAL REVENUES	4,372.5	4,639.7	9,063.4	9,232.3
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,424.6	1,564.4	3,131.0	3,065.1
Other Operation	631.2	619.8	1,311.2	1,282.0
Maintenance	340.0	326.5	657.3	611.5
Loss on the Expected Sale of the Kentucky Operations	—	68.8	—	68.8
Loss on the Expected Sale of the Competitive Contracted Renewable Portfolio	—	—	112.0	—
Gain on Sale of Mineral Rights	—	(116.3)	—	(116.3)
Depreciation and Amortization	741.6	802.6	1,517.1	1,595.0
Taxes Other Than Income Taxes	360.4	369.5	755.3	733.7
TOTAL EXPENSES	3,497.8	3,635.3	7,483.9	7,239.8
OPERATING INCOME	874.7	1,004.4	1,579.5	1,992.5
Other Income (Expense):				
Other Income (Expense)	14.4	(12.7)	29.1	(10.4)
Allowance for Equity Funds Used During Construction	41.0	28.6	72.3	59.6
Non-Service Cost Components of Net Periodic Benefit Cost	55.2	47.1	110.7	94.3
Interest Expense	(460.0)	(327.6)	(875.7)	(641.0)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	525.3	739.8	915.9	1,495.0
Income Tax Expense	28.6	54.0	39.0	106.8
Equity Earnings (Loss) of Unconsolidated Subsidiaries	19.4	(165.0)	39.6	(149.3)
NET INCOME	516.1	520.8	916.5	1,238.9
Net Loss Attributable to Noncontrolling Interests	(5.1)	(3.7)	(1.7)	(0.3)
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 521.2	$ 524.5	$ 918.2	$ 1,239.2
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	514,879,144	513,623,431	514,529,837	509,857,710
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.01	$ 1.02	$ 1.78	$ 2.43
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	516,242,919	515,162,210	515,922,446	511,391,735
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.01	$ 1.02	$ 1.78	$ 2.42

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	**2022**	**2023**	**2022**
et Income	$ 516.1	$ 520.8	$ 916.5	$ 1,238.9
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $9.3 and $35.2 for the Three Months Ended June 30, 2023 and 2022, Respectively, and $(31.2) and $101.1 for the Six Months Ended June 30, 2023 and 2022, Respectively	34.8	132.4	(117.6)	380.4
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.8) and $(3.1) for the Three Months Ended June 30, 2023 and 2022, Respectively, and $(5.1) and $(3.7) for the Six Months Ended June 30, 2023 and 2022, Respectively	(3.1)	(11.6)	(19.2)	(13.8)
Reclassifications of KPCo Pension and OPEB Regulatory Assets, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2023 and 2022, Respectively, and $4.4 and $0 for the Six Months Ended June 30, 2023 and 2022, Respectively	—	—	16.7	—
OTAL OTHER COMPREHENSIVE INCOME (LOSS)	31.7	120.8	(120.1)	366.6
OTAL COMPREHENSIVE INCOME	547.8	641.6	796.4	1,605.5
Total Comprehensive Loss Attributable To Noncontrolling Interests	(5.1)	(3.7)	(1.7)	(0.3)
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 552.9	$ 645.3	$ 798.1	$ 1,605.8

e Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2023 and 2022
(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, 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) (a)		(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) (a)		(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
TOTAL EQUITY – DECEMBER 31, 2022	525.1	$ 3,413.1	$ 8,051.0	$ 12,345.6	$ 83.7	$ 229.0	$ 24,122.4
Issuance of Common Stock	0.8	5.1	36.0				41.1
Common Stock Dividends				(428.8) (b)		(3.0)	(431.8)
Other Changes in Equity			(12.7)			0.2	(12.5)
Net Income				397.0		3.4	400.4
Other Comprehensive Loss					(151.8)		(151.8)
TOTAL EQUITY – MARCH 31, 2023	525.9	3,418.2	8,074.3	12,313.8	(68.1)	229.6	23,967.8
Issuance of Common Stock	0.5	3.3	33.2				36.5
Common Stock Dividends				(429.5) (b)		(2.3)	(431.8)
Other Changes in Equity			3.3				3.3
Net Income (Loss)				521.2		(5.1)	516.1
Other Comprehensive Income					31.7		31.7
TOTAL EQUITY – JUNE 30, 2023	526.4	$ 3,421.5	$ 8,110.8	$ 12,405.5	$ (36.4)	$ 222.2	$ 24,123.6

(a) Cash dividends declared per AEP common share were $0.78.
(b) Cash dividends declared per AEP common share were $0.83.

ondensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2023 and December 31, 2022
(in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents	$ 304.9	$ 509.4
Restricted Cash (June 30, 2023 and December 31, 2022 Amounts Include $45.8 and $47.1, Respectively, Related to Transition Funding, Restoration Funding and Appalachian Consumer Rate Relief Funding)	45.8	47.1
Other Temporary Investments (June 30, 2023 and December 31, 2022 Amounts Include $190.9 and $182.9, Respectively, Related to EIS and Transource Energy)	202.5	187.6
Accounts Receivable:		
Customers	990.8	1,145.1
Accrued Unbilled Revenues	179.2	322.9
Pledged Accounts Receivable – AEP Credit	1,226.6	1,207.4
Miscellaneous	47.9	49.7
Allowance for Uncollectible Accounts	(58.6)	(57.1)
Total Accounts Receivable	2,385.9	2,668.0
Fuel	705.9	435.1
Materials and Supplies	975.9	915.1
Risk Management Assets	279.5	348.8
Accrued Tax Benefits	191.8	99.4
Regulatory Asset for Under-Recovered Fuel Costs	1,256.4	1,310.0
Assets Held for Sale	1,382.8	—
Prepayments and Other Current Assets	309.9	255.0
TOTAL CURRENT ASSETS	8,041.3	6,775.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,113.5	25,834.2
Transmission	34,145.5	33,266.9
Distribution	28,033.8	27,138.8
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	6,187.6	5,971.8
Construction Work in Progress	5,935.4	4,809.7
Total Property, Plant and Equipment	98,415.8	97,021.4
Accumulated Depreciation and Amortization	23,734.4	23,682.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	74,681.4	73,339.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,672.8	4,762.0
Securitized Assets	394.3	446.0
Spent Nuclear Fuel and Decommissioning Trusts	3,648.8	3,341.2
Goodwill	52.5	52.5
Long-term Risk Management Assets	266.8	284.1
Operating Lease Assets	634.1	645.5
Deferred Charges and Other Noncurrent Assets	3,610.1	3,757.4
TOTAL OTHER NONCURRENT ASSETS	13,279.4	13,288.7
TOTAL ASSETS	$ 96,002.1	$ 93,403.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2023 and December 31, 2022
(in millions, except per-share and share amounts)
(Unaudited)

			June 30, 2023	December 31, 2022
CURRENT LIABILITIES				
Accounts Payable			$ 2,433.9	$ 2,670.8
Short-term Debt:				
Securitized Debt for Receivables – AEP Credit			750.0	750.0
Other Short-term Debt			3,117.6	3,362.2
Total Short-term Debt			3,867.6	4,112.2
Long-term Debt Due Within One Year (June 30, 2023 and December 31, 2022 Amounts Include $196.2 and $218.2, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			3,380.3	2,486.4
Risk Management Liabilities			176.2	145.2
Customer Deposits			382.2	408.8
Accrued Taxes			1,366.5	1,714.6
Accrued Interest			402.9	336.5
Obligations Under Operating Leases			116.6	113.6
Liabilities Held for Sale			64.8	—
Other Current Liabilities			1,076.1	1,278.2
TOTAL CURRENT LIABILITIES			13,267.1	13,266.3
NONCURRENT LIABILITIES				
Long-term Debt (June 30, 2023 and December 31, 2022 Amounts Include $591.3 and $755.3, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			36,762.0	34,314.6
Long-term Risk Management Liabilities			275.3	345.2
Deferred Income Taxes			9,157.7	8,896.9
Regulatory Liabilities and Deferred Investment Tax Credits			8,121.1	8,115.6
Asset Retirement Obligations			2,879.9	2,879.3
Employee Benefits and Pension Obligations			248.9	257.3
Obligations Under Operating Leases			533.6	552.5
Deferred Credits and Other Noncurrent Liabilities			568.2	607.3
TOTAL NONCURRENT LIABILITIES			58,546.7	55,968.7
TOTAL LIABILITIES			71,813.8	69,235.0
Rate Matters (Note 4)				
Commitments and Contingencies (Note 5)				
MEZZANINE EQUITY				
Contingently Redeemable Performance Share Awards			64.7	45.9
TOTAL MEZZANINE EQUITY			64.7	45.9
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2023	2022		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	526,387,081	525,099,321		
(11,233,240 Shares were Held in Treasury as of June 30, 2023 and December 31, 2022, Respectively)			3,421.5	3,413.1
Paid-in Capital			8,110.8	8,051.0
Retained Earnings			12,405.5	12,345.6
Accumulated Other Comprehensive Income (Loss)			(36.4)	83.7
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			23,901.4	23,893.4
Noncontrolling Interests			222.2	229.0
TOTAL EQUITY			24,123.6	24,122.4
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$ 96,002.1	$ 93,403.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
OPERATING ACTIVITIES		
Net Income	$ 916.5	$ 1,238.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,517.1	1,595.0
Deferred Income Taxes	135.8	21.4
Loss on the Expected Sale of the Competitive Contracted Renewable Portfolio	112.0	—
Loss on the Expected Sale of the Kentucky Operations	—	68.8
Impairment of Equity Method Investment	—	185.5
Allowance for Equity Funds Used During Construction	(72.3)	(59.6)
Mark-to-Market of Risk Management Contracts	(124.7)	431.4
Property Taxes	202.7	191.6
Deferred Fuel Over/Under-Recovery, Net	342.5	(599.5)
Gain on Sale of Mineral Rights	—	(116.3)
Change in Other Noncurrent Assets	(375.5)	(49.3)
Change in Other Noncurrent Liabilities	(55.4)	144.5
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	277.8	(445.8)
Fuel, Materials and Supplies	(315.1)	(110.5)
Accounts Payable	62.6	484.8
Accrued Taxes, Net	(433.7)	(218.2)
Other Current Assets	(76.6)	69.9
Other Current Liabilities	(232.1)	158.1
Net Cash Flows from Operating Activities	1,881.6	2,990.7
INVESTING ACTIVITIES		
Construction Expenditures	(4,049.7)	(3,138.1)
Purchases of Investment Securities	(1,235.6)	(1,254.8)
Sales of Investment Securities	1,206.3	1,244.9
Acquisitions of Nuclear Fuel	(73.9)	(67.7)
Acquisitions of Renewable Energy Facilities	(145.7)	(1,207.3)
Proceeds from Sales of Assets	1.0	208.5
Other Investing Activities	32.1	15.5
Net Cash Flows Used for Investing Activities	(4,265.5)	(4,199.0)
FINANCING ACTIVITIES		
Issuance of Common Stock	77.6	812.7
Issuance of Long-term Debt	3,958.8	2,639.1
Issuance of Short-term Debt with Original Maturities greater than 90 Days	597.4	271.0
Change in Short-term Debt with Original Maturities less than 90 Days, Net	(688.2)	(268.9)
Retirement of Long-term Debt	(641.7)	(582.4)
Redemption of Short-term Debt with Original Maturities Greater than 90 Days	(153.8)	(486.1)
Principal Payments for Finance Lease Obligations	(40.6)	(106.2)
Dividends Paid on Common Stock	(863.6)	(803.5)
Other Financing Activities	(67.8)	(97.6)
Net Cash Flows from Financing Activities	2,178.1	1,378.1
Net Increase (Decrease) in Cash and Cash Equivalents	(205.8)	169.8
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	556.5	451.4
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 350.7	$ 621.2
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 773.5	$ 591.2
Net Cash Paid for Income Taxes	9.9	95.5
Noncash Acquisitions Under Finance Leases	25.6	13.7
Construction Expenditures Included in Current Liabilities as of June 30,	966.6	849.1
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	(36.0)	—

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in millions of KWhs)			
Retail:				
Residential	3,082	3,531	5,614	6,374
Commercial	3,443	3,091	6,187	5,239
Industrial	3,171	3,023	6,279	5,450
Miscellaneous	153	173	291	314
Total Retail	9,849	9,818	18,371	17,377

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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in degree days)			
Actual – Heating (a)	2	—	143	278
Normal – Heating (b)	3	3	197	193
Actual – Cooling (c)	955	1,135	1,226	1,223
Normal – Cooling (b)	940	925	1,067	1,051

(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.

AEP Texas Inc. and Subsidiaries
Reconciliation of 2022 to 2023 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2022 Net Income	$ 90.0	$ 159.6
Changes in Revenues:		
Retail Revenues	(37.1)	(35.5)
Transmission Revenues	20.1	32.5
Other Revenues	(0.6)	(1.8)
Total Change in Revenues	(17.6)	(4.8)
Changes in Expenses and Other:		
Other Operation and Maintenance	46.6	23.7
Depreciation and Amortization	1.3	(0.9)
Taxes Other Than Income Taxes	(1.8)	(8.0)
Interest Income	(0.7)	(0.4)
Allowance for Equity Funds Used During Construction	1.6	3.6
Non-Service Cost Components of Net Periodic Benefit Cost	0.7	1.3
Interest Expense	(4.0)	(15.4)
Total Change in Expenses and Other	43.7	3.9
Income Tax Expense	(7.0)	(2.0)
2023 Net Income	$ 109.1	$ 156.7

Second Quarter of 2023 Compared to Second Quarter of 2022

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

- **Retail Revenues** decreased $37 million primarily due to the following:
  - A $19 million decrease in revenue from rate riders primarily due to a historical period over recovery. This decrease is partially offset in Other Operations and Maintenance expenses below.
  - An $11 million decrease in weather-normalized revenues in all retail classes.
  - An $8 million decrease in weather-related usage primarily due to a 16% decrease in cooling degree days.
- **Transmission Revenues** increased $20 million primarily due to the following:
  - A $14 million increase due to increased load.
  - A $6 million increase in interim rates driven by increased transmission investments.

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

- **Other Operation and Maintenance** expenses decreased $47 million primarily due to the following:
  - A $28 million decrease due to legislation passed in Texas in May 2023 allowing employee financially based incentives to be recovered.
  - An $18 million decrease in ERCOT transmission expenses. This increase was offset in Retail Revenues above.
- **Interest Expense** increased $4 million due to higher long term debt balances and higher interest rates.
- **Income Tax Expense** increased $7 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022
The major components of the decrease in revenues were as follows:

- **Retail Revenues** decreased $36 million primarily due to the following:
  - A $24 million decrease in weather-normalized revenues in all retail classes.
  - An $8 million decrease in weather-related usage primarily due to a 49% decrease in heating degree days.
- **Transmission Revenues** increased $33 million primarily due to the following:
  - An $18 million increase in interim rates driven by increased transmission investment.
  - A $14 million increase due to increased load.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $24 million primarily due to the following:
  - A $28 million decrease due to legislation passed in Texas in May 2023 allowing employee financially based incentives to be recovered.
  - A $5 million decrease in employee-related expenses.
  - A $4 million decrease in ERCOT transmission expenses. This increase was offset in Retail Revenues above.

These decreases were partially offset by:
  - An $11 million increase in distribution-related expenses.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to higher property taxes driven by increased distribution and transmission investment.
- **Interest Expense** increased $15 million primarily due to higher long-term debt balances and higher interest rates.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
REVENUES				
Electric Transmission and Distribution	$ 459.4	$ 476.9	$ 887.1	$ 891.6
Sales to AEP Affiliates	1.3	0.8	2.5	1.7
Other Revenues	0.5	1.1	1.1	2.2
TOTAL REVENUES	461.2	478.8	890.7	895.5
EXPENSES				
Other Operation	93.9	142.0	240.8	267.8
Maintenance	26.3	24.8	50.7	47.4
Depreciation and Amortization	114.9	116.2	225.9	225.0
Taxes Other Than Income Taxes	44.8	43.0	88.3	80.3
TOTAL EXPENSES	279.9	326.0	605.7	620.5
OPERATING INCOME	181.3	152.8	285.0	275.0
Other Income (Expense):				
Interest Income	0.6	1.3	1.0	1.4
Allowance for Equity Funds Used During Construction	5.3	3.7	11.6	8.0
Non-Service Cost Components of Net Periodic Benefit Cost	4.8	4.1	9.6	8.3
Interest Expense	(56.3)	(52.3)	(113.2)	(97.8)
INCOME BEFORE INCOME TAX EXPENSE	135.7	109.6	194.0	194.9
Income Tax Expense	26.6	19.6	37.3	35.3
NET INCOME	$ 109.1	$ 90.0	$ 156.7	$ 159.6

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Net Income	$ 109.1	$ 90.0	$ 156.7	$ 159.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.8 and $0 for the Three Months Ended June 30, 2023 and 2022, Respectively, and $0.8 and $0.1 for the Six Months Ended June 30, 2023 and 2022, Respectively	3.2	0.2	3.2	0.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2023 and 2022, Respectively, and $(0.1) and $0 for the Six Months Ended June 30, 2023 and 2022, Respectively	—	—	(0.6)	—
TOTAL OTHER COMPREHENSIVE INCOME	3.2	0.2	2.6	0.5
TOTAL COMPREHENSIVE INCOME	$ 112.3	$ 90.2	$ 159.3	$ 160.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 1,558.2	$ 2,354.7	$ (8.6)	$ 3,904.3
Capital Contribution from Parent	100.0			100.0
Net Income		47.6		47.6
Other Comprehensive Loss			(0.6)	(0.6)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2023	1,658.2	2,402.3	(9.2)	4,051.3
Capital Contribution from Parent	175.3			175.3
Return of Capital to Parent	(4.3)			(4.3)
Net Income		109.1		109.1
Other Comprehensive Income			3.2	3.2
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2023	$ 1,829.2	$ 2,511.4	$ (6.0)	$ 4,334.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2023 and December 31, 2022
(in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents	$ 0.1	$ 0.1
Restricted Cash (June 30, 2023 and December 31, 2022 Amounts Include \$30.7 and \$32.7, Respectively, Related to Transition Funding and Restoration Funding)	30.7	32.7
Advances to Affiliates	6.9	6.9
Accounts Receivable:		
Customers	173.2	150.9
Affiliated Companies	22.9	11.9
Accrued Unbilled Revenues	91.6	91.4
Miscellaneous	0.5	0.2
Allowance for Uncollectible Accounts	(4.9)	(4.2)
Total Accounts Receivable	283.3	250.2
Materials and Supplies	157.3	138.8
Prepayments and Other Current Assets	8.9	18.2
TOTAL CURRENT ASSETS	487.2	446.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	6,487.9	6,301.5
Distribution	5,572.7	5,312.8
Other Property, Plant and Equipment	1,098.3	1,022.8
Construction Work in Progress	984.9	805.2
Total Property, Plant and Equipment	14,143.8	13,442.3
Accumulated Depreciation and Amortization	1,829.1	1,760.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	12,314.7	11,681.6
OTHER NONCURRENT ASSETS		
Regulatory Assets	326.5	298.3
Securitized Assets (June 30, 2023 and December 31, 2022 Amounts Include \$247.8 and \$286.4, Respectively, Related to Transition Funding and Restoration Funding)	247.8	286.4
Deferred Charges and Other Noncurrent Assets	238.2	179.0
TOTAL OTHER NONCURRENT ASSETS	812.5	763.7
TOTAL ASSETS	$ 13,614.4	$ 12,892.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2023 and December 31, 2022
(in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT LIABILITIES		
Advances from Affiliates	$ 135.9	$ 96.5
Accounts Payable:		
General	247.2	331.0
Affiliated Companies	34.3	34.7
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2023 and December 31, 2022 Amounts Include $94.7 and $93.5, Respectively, Related to Transition Funding and Restoration Funding)	154.7	278.5
Accrued Taxes	138.7	95.5
Accrued Interest (June 30, 2023 and December 31, 2022 Amounts Include $2.1 and $2.2, Respectively, Related to Transition Funding and Restoration Funding)	50.5	48.3
Obligations Under Operating Leases	29.8	28.6
Other Current Liabilities	132.6	130.7
TOTAL CURRENT LIABILITIES	923.7	1,043.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2023 and December 31, 2022 Amounts Include $177 and $221, Respectively, Related to Transition Funding and Restoration Funding)	5,782.8	5,379.3
Deferred Income Taxes	1,180.3	1,144.2
Regulatory Liabilities and Deferred Investment Tax Credits	1,250.6	1,259.6
Obligations Under Operating Leases	59.2	67.8
Deferred Credits and Other Noncurrent Liabilities	83.2	93.2
TOTAL NONCURRENT LIABILITIES	8,356.1	7,944.1
TOTAL LIABILITIES	9,279.8	8,987.9
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	1,829.2	1,558.2
Retained Earnings	2,511.4	2,354.7
Accumulated Other Comprehensive Income (Loss)	(6.0)	(8.6)
TOTAL COMMON SHAREHOLDER'S EQUITY	4,334.6	3,904.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 13,614.4	$ 12,892.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
OPERATING ACTIVITIES		
Net Income	$ 156.7	$ 159.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	225.9	225.0
Deferred Income Taxes	28.5	24.6
Allowance for Equity Funds Used During Construction	(11.6)	(8.0)
Mark-to-Market of Risk Management Contracts	0.4	(0.2)
Property Taxes	(60.0)	(54.8)
Change in Other Noncurrent Assets	(89.7)	(25.9)
Change in Other Noncurrent Liabilities	7.8	32.1
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(33.1)	(70.3)
Materials and Supplies	(18.5)	(24.1)
Accounts Payable	1.9	17.9
Accrued Taxes, Net	50.2	34.0
Other Current Assets	2.9	(0.8)
Other Current Liabilities	(34.4)	31.9
Net Cash Flows from Operating Activities	227.0	341.0
INVESTING ACTIVITIES		
Construction Expenditures	(834.2)	(647.6)
Change in Advances to Affiliates, Net	—	(634.0)
Other Investing Activities	20.2	22.3
Net Cash Flows Used for Investing Activities	(814.0)	(1,259.3)
FINANCING ACTIVITIES		
Capital Contribution from Parent	275.3	1.3
Return of Capital to Parent	(4.3)	—
Issuance of Long-term Debt – Nonaffiliated	445.9	1,188.6
Change in Advances from Affiliates, Net	39.4	(26.9)
Retirement of Long-term Debt – Nonaffiliated	(168.2)	(242.0)
Principal Payments for Finance Lease Obligations	(3.7)	(3.4)
Other Financing Activities	0.6	—
Net Cash Flows from Financing Activities	585.0	917.6
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(2.0)	(0.7)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	32.8	30.5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 30.8	$ 29.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 108.3	$ 88.8
Net Cash Paid for Income Taxes	0.7	5.9
Noncash Acquisitions Under Finance Leases	2.6	3.0
Construction Expenditures Included in Current Liabilities as of June 30,	147.2	135.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

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 June 30,	
	2023	2022
	(in millions)	
Plant In Service	$ 13,269.6	$ 11,829.5
Construction Work in Progress	1,918.9	1,687.6
Accumulated Depreciation and Amortization	1,150.8	901.0
Total Transmission Property, Net	$ 14,037.7	$ 12,616.1

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of 2022 to 2023 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2022 Net Income	$ 118.5	$ 273.9
Changes in Transmission Revenues:		
Transmission Revenues	80.5	121.7
Total Change in Transmission Revenues	80.5	121.7
Changes in Expenses and Other:		
Other Operation and Maintenance	2.7	(2.4)
Depreciation and Amortization	(10.7)	(22.8)
Taxes Other Than Income Taxes	0.7	(8.5)
Interest Income	2.4	3.8
Allowance for Equity Funds Used During Construction	7.8	8.6
Interest Expense	(11.4)	(18.9)
Total Change in Expenses and Other	(8.5)	(40.2)
Income Tax Expense	(14.8)	(17.0)
2023 Net Income	$ 175.7	$ 338.4

Second Quarter of 2023 Compared to Second Quarter of 2022

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

- **Transmission Revenues** increased $80 million primarily due to the following:
  - A $41 million increase due to continued investment in transmission assets.
  - A $33 million increase due to affiliated transmission formula rate true-up activity. This increase was offset in Other Operation and Maintenance expense across the other Registrant Subsidiaries.
  - A $6 million increase due to nonaffiliated transmission formula rate true-up activity.

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

- **Depreciation and Amortization** expenses increased $11 million primarily due to a higher depreciable base.
- **Allowance for Equity Funds Used During Construction** increased $8 million primarily due to higher AFUDC equity rates and CWIP.
- **Interest Expense** increased $11 million due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $15 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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

- **Transmission Revenues** increased $122 million primarily due to the following:
  - An $83 million increase due to continued investment in transmission assets.
  - A $33 million increase due to affiliated transmission formula rate true-up activity. This increase was offset in Other Operation and Maintenance expense across the other Registrant Subsidiaries.
  - A $6 million increase due to nonaffiliated transmission formula rate true-up activity.

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

- **Depreciation and Amortization** expenses increased $23 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $9 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $9 million primarily due to higher AFUDC equity rates and CWIP.
- **Interest Expense** increased $19 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $17 million primarily due to an increase in pretax book income.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
REVENUES				
Transmission Revenues	$ 90.2	$ 85.6	$ 180.2	$ 172.6
Sales to AEP Affiliates	365.8	333.9	723.2	658.9
Provision for Refund – Affiliated	(8.3)	(46.8)	(13.1)	(56.4)
Provision for Refund – Nonaffiliated	(2.8)	(8.3)	(3.8)	(10.3)
TOTAL REVENUES	444.9	364.4	886.5	764.8
EXPENSES				
Other Operation	26.4	29.6	55.4	55.1
Maintenance	4.3	3.8	9.2	7.1
Depreciation and Amortization	96.4	85.7	191.6	168.8
Taxes Other Than Income Taxes	68.0	68.7	142.8	134.3
TOTAL EXPENSES	195.1	187.8	399.0	365.3
OPERATING INCOME	249.8	176.6	487.5	399.5
Other Income (Expense):				
Interest Income - Affiliated	2.6	0.2	4.1	0.3
Allowance for Equity Funds Used During Construction	23.1	15.3	39.5	30.9
Interest Expense	(50.7)	(39.3)	(95.9)	(77.0)
INCOME BEFORE INCOME TAX EXPENSE	224.8	152.8	435.2	353.7
Income Tax Expense	49.1	34.3	96.8	79.8
NET INCOME	$ 175.7	$ 118.5	$ 338.4	$ 273.9

AEPTCo is wholly-owned by AEP Transmission Holdco.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total
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
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2022	$ 3,022.3	$ 2,850.7	$ 5,873.0
Capital Contribution from Member	25.0		25.0
Dividends Paid to Member		(55.0)	(55.0)
Net Income		162.7	162.7
TOTAL MEMBER'S EQUITY – MARCH 31, 2023	3,047.3	2,958.4	6,005.7
Return of Capital to Member	(8.6)		(8.6)
Dividends Paid to Member		(30.0)	(30.0)
Net Income		175.7	175.7
TOTAL MEMBER'S EQUITY – JUNE 30, 2023	$ 3,038.7	$ 3,104.1	$ 6,142.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2023 and December 31, 2022
(in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT ASSETS		
Advances to Affiliates	$ 79.4	$ 4.4
Accounts Receivable:		
Customers	91.1	46.9
Affiliated Companies	179.4	119.5
Total Accounts Receivable	270.5	166.4
Materials and Supplies	15.5	10.7
Prepayments and Other Current Assets	1.8	7.2
TOTAL CURRENT ASSETS	367.2	188.7
TRANSMISSION PROPERTY		
Transmission Property	12,780.0	12,335.4
Other Property, Plant and Equipment	489.6	476.8
Construction Work in Progress	1,918.9	1,554.7
Total Transmission Property	15,188.5	14,366.9
Accumulated Depreciation and Amortization	1,150.8	1,027.0
TOTAL TRANSMISSION PROPERTY – NET	14,037.7	13,339.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	5.8	7.2
Deferred Property Taxes	155.9	266.6
Deferred Charges and Other Noncurrent Assets	9.9	11.8
TOTAL OTHER NONCURRENT ASSETS	171.6	285.6
TOTAL ASSETS	$ 14,576.5	$ 13,814.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
June 30, 2023 and December 31, 2022
(Unaudited)

	June 30, 2023	December 31, 2022
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 74.4	$ 229.3
Accounts Payable:		
General	387.4	427.8
Affiliated Companies	104.9	82.7
Long-term Debt Due Within One Year – Nonaffiliated	60.0	60.0
Accrued Taxes	392.4	529.8
Accrued Interest	40.1	28.8
Obligations Under Operating Leases	1.4	1.3
Other Current Liabilities	12.3	8.3
TOTAL CURRENT LIABILITIES	1,072.9	1,368.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	5,413.0	4,722.8
Deferred Income Taxes	1,107.3	1,056.5
Regulatory Liabilities	768.9	723.3
Obligations Under Operating Leases	1.8	1.5
Deferred Credits and Other Noncurrent Liabilities	69.8	69.1
TOTAL NONCURRENT LIABILITIES	7,360.8	6,573.2
TOTAL LIABILITIES	8,433.7	7,941.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	3,038.7	3,022.3
Retained Earnings	3,104.1	2,850.7
TOTAL MEMBER'S EQUITY	6,142.8	5,873.0
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 14,576.5	$ 13,814.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Six Months Ended June 30,			
	2023		2022	
OPERATING ACTIVITIES				
Net Income	$	338.4	$	273.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization		191.6		168.8
Deferred Income Taxes		42.7		37.3
Allowance for Equity Funds Used During Construction		(39.5)		(30.9)
Property Taxes		110.7		101.4
Change in Other Noncurrent Assets		3.4		1.8
Change in Other Noncurrent Liabilities		1.7		44.3
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net		(104.1)		(36.7)
Materials and Supplies		(4.8)		(2.2)
Accounts Payable		64.6		13.1
Accrued Taxes, Net		(133.3)		(107.6)
Other Current Assets		1.3		0.9
Other Current Liabilities		10.2		(0.9)
Net Cash Flows from Operating Activities		482.9		463.2
INVESTING ACTIVITIES				
Construction Expenditures		(876.1)		(730.9)
Change in Advances to Affiliates, Net		(75.0)		(109.8)
Other Investing Activities		2.6		(8.0)
Net Cash Flows Used for Investing Activities		(948.5)		(848.7)
FINANCING ACTIVITIES				
Capital Contribution from Member		25.0		2.8
Return of Capital to Member		(8.6)		—
Issuance of Long-term Debt – Nonaffiliated		689.1		540.9
Change in Advances from Affiliates, Net		(154.9)		(68.2)
Dividends Paid to Member		(85.0)		(90.0)
Net Cash Flows from Financing Activities		465.6		385.5
Net Change in Cash and Cash Equivalents		—		—
Cash and Cash Equivalents at Beginning of Period		—		—
Cash and Cash Equivalents at End of Period	$	—	$	—
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	82.8	$	74.0
Net Cash Paid for Income Taxes		32.0		39.7
Construction Expenditures Included in Current Liabilities as of June 30,		238.4		228.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in millions of KWhs)			
Retail:				
Residential	1,987	2,223	5,046	5,755
Commercial	1,346	1,460	2,749	2,979
Industrial	2,135	2,225	4,244	4,444
Miscellaneous	190	205	390	418
Total Retail	5,658	6,113	12,429	13,596
Wholesale	514	262	1,003	625
Total KWhs	6,172	6,375	13,432	14,221

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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in degree days)			
Actual – Heating (a)	69	94	928	1,368
Normal – Heating (b)	87	89	1,408	1,408
Actual – Cooling (c)	225	421	233	423
Normal – Cooling (b)	379	372	385	378

(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.

Appalachian Power Company and Subsidiaries
Reconciliation of 2022 to 2023 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2022 Net Income	$ 90.2	$ 210.4
Changes in Gross Margin:		
Retail Margins	20.2	33.2
Margins from Off-system Sales	0.4	2.6
Transmission Revenues	2.4	2.6
Other Revenues	(2.3)	(6.5)
Total Change in Gross Margin	20.7	31.9
Changes in Expenses and Other:		
Other Operation and Maintenance	(46.7)	(52.6)
Depreciation and Amortization	4.8	7.0
Taxes Other Than Income Taxes	(1.9)	(3.5)
Interest Income	0.5	1.0
Allowance for Equity Funds Used During Construction	0.1	0.5
Non-Service Cost Components of Net Periodic Benefit Cost	1.0	1.8
Interest Expense	(11.8)	(22.8)
Total Change in Expenses and Other	(54.0)	(68.6)
Income Tax Expense	(14.0)	(18.3)
2023 Net Income	$ 42.9	$ 155.4

Second Quarter of 2023 Compared to Second Quarter of 2022

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 $20 million primarily due to the following:
  - A $14 million increase due to a base rate increase in Virginia implemented in October 2022 following the Virginia Supreme Court remand. This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $9 million increase in deferred fuel primarily related to the timing of recoverable PJM expenses. This increase was offset in Other Operation and Maintenance expenses below.
  - An $8 million increase due to lower customer refunds related to Tax Reform. This increase was offset in Income Tax Expense below.
  - A $6 million increase due to rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.

  These increases were partially offset by:
  - An $18 million decrease in weather-related usage primarily driven by a 28% decrease in heating degree days and a 46% decrease in cooling degree days.

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

- **Other Operation and Maintenance** expenses increased $47 million primarily due to the following:
  - A $14 million increase due to gains from the sale of land in 2022.
  - An $11 million increase in distribution expenses primarily due to storm restoration costs.
  - A $7 million increase due to the amortization of the regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to under-earnings during the 2017-2019 Triennial Review. This increase was offset in Retail Margins above.
  - A $6 million increase in transmission expenses primarily due to formula rate true-up activity.
- **Interest Expense** increased $12 million primarily due to higher debt balances and interest rates.
- **Income Tax Expense** increased $14 million primarily due to the following:
  - A $14 million decrease in amortization of Excess ADIT. This decrease was partially offset in Retail Margins above.
  - A $5 million increase in unfavorable discrete adjustments in 2023.

  These increases were partially offset by:
  - A $7 million decrease due to a decrease in pretax book income.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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 $33 million primarily due to the following:
  - A $29 million increase due to a base rate increase in Virginia implemented in October 2022 following the Virginia Supreme Court remand. This increase was partially offset in Other Operation and Maintenance expenses below.
  - A $17 million increase due to lower customer refunds related to Tax Reform. This increase was offset in Income Tax Expense below.
  - A $12 million increase in deferred fuel primarily related to the timing of recoverable PJM expenses. This increase was offset in Other Operation and Maintenance expenses below.
  - An $11 million increase in weather-normalized margins primarily driven by increases in the residential class.
  - A $9 million increase due to rider revenues in Virginia and West Virginia. This increase was partially offset in other expense items below.
  - An $8 million increase due to lower amortization expenses related to the Virginia CCR. This increase was offset in other expense items below.
  - A $4 million increase driven by sales of renewable energy credits in Virginia.

  These increases were partially offset by:
  - A $62 million decrease in weather-related usage primarily driven by a 32% decrease in heating degree days and a 45% decrease in cooling degree days.
- **Other Revenues** decreased $7 million primarily due to pole attachment revenue.

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

- **Other Operation and Maintenance** expenses increased $53 million primarily due to the following:
  - A $15 million increase in distribution expenses primarily due to storm restoration costs.
  - A $14 million increase due to the amortization of the regulatory asset in accordance with the August 2022 Virginia Supreme Court opinion related to under-earnings during the 2017-2019 Triennial Review. This increase was offset in Retail Margins above.
  - A $14 million increase due to gains from the sale of land in 2022.
  - A $6 million increase in accounts receivable factoring expenses as a result of increased interest rates.
- **Depreciation and Amortization** expenses decreased $7 million primarily due to adjustments related to various retail riders. This decrease was partially offset in Retail Margins above.
- **Interest Expense** increased $23 million primarily due to higher long-term debt balances and interest rates.

- **Income Tax Expense** increased $18 million primarily due to the following:
  - A $15 million decrease in amortization of Excess ADIT. This decrease was partially offset in Retail Margins above.
  - A $10 million increase in unfavorable discrete adjustments in 2023.

These increases were partially offset by:
  - An $8 million decrease due to a decrease in pretax book income.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	**2022**	**2023**	**2022**
REVENUES				
Electric Generation, Transmission and Distribution	$ 762.5	$ 704.9	$ 1,677.0	$ 1,552.0
Sales to AEP Affiliates	61.1	63.1	130.7	120.0
Other Revenues	2.9	5.6	6.5	8.9
TOTAL REVENUES	826.5	773.6	1,814.2	1,680.9
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	277.9	245.7	617.6	516.2
Other Operation	189.9	147.1	381.7	332.0
Maintenance	75.1	71.2	148.2	145.3
Depreciation and Amortization	138.1	142.9	281.1	288.1
Taxes Other Than Income Taxes	41.2	39.3	83.0	79.5
TOTAL EXPENSES	722.2	646.2	1,511.6	1,361.1
OPERATING INCOME	104.3	127.4	302.6	319.8
Other Income (Expense):				
Interest Income	0.8	0.3	1.4	0.4
Allowance for Equity Funds Used During Construction	2.7	2.6	5.1	4.6
Non-Service Cost Components of Net Periodic Benefit Cost	8.2	7.2	16.3	14.5
Interest Expense	(66.9)	(55.1)	(132.2)	(109.4)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	49.1	82.4	193.2	229.9
Income Tax Expense (Benefit)	6.2	(7.8)	37.8	19.5
NET INCOME	$ 42.9	$ 90.2	$ 155.4	$ 210.4

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	**2022**	**2023**	**2022**
Net Income	$ 42.9	$ 90.2	$ 155.4	$ 210.4
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2023 and 2022, Respectively, and $(0.1) and $(0.1) for the Six Months Ended June 30, 2023 and 2022, Respectively	(0.2)	(0.2)	(0.4)	(0.4)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.2) and $(0.3) for the Three Months Ended June 30, 2023 and 2022, Respectively, and $(0.4) and $(0.6) for the Six Months Ended June 30, 2023 and 2022, Respectively	(0.8)	(1.0)	(1.6)	(2.1)
TOTAL OTHER COMPREHENSIVE LOSS	(1.0)	(1.2)	(2.0)	(2.5)
TOTAL COMPREHENSIVE INCOME	$ 41.9	$ 89.0	$ 153.4	$ 207.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER’S EQUITY
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2022	$ 260.4	$ 1,828.7	$ 2,891.1	$ (4.8)	$ 4,975.4
Net Income			112.5		112.5
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2023	260.4	1,828.7	3,003.6	(5.8)	5,086.9
Capital Contribution from Parent		4.3			4.3
Net Income			42.9		42.9
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2023	$ 260.4	$ 1,833.0	$ 3,046.5	$ (6.8)	$ 5,133.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2023 and December 31, 2022
(in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6.8	$ 7.5
Restricted Cash for Securitized Funding	15.1	14.4
Advances to Affiliates	18.9	19.8
Accounts Receivable:		
Customers	138.1	168.9
Affiliated Companies	121.5	94.0
Accrued Unbilled Revenues	35.6	91.3
Miscellaneous	0.5	0.3
Allowance for Uncollectible Accounts	(1.6)	(1.7)
Total Accounts Receivable	294.1	352.8
Fuel	267.1	158.9
Materials and Supplies	136.5	130.6
Risk Management Assets	39.2	69.1
Regulatory Asset for Under-Recovered Fuel Costs	586.0	473.1
Prepayments and Other Current Assets	28.9	33.4
TOTAL CURRENT ASSETS	1,392.6	1,259.6
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,903.0	6,776.8
Transmission	4,536.9	4,482.8
Distribution	5,067.5	4,933.0
Other Property, Plant and Equipment	922.7	883.3
Construction Work in Progress	790.9	705.3
Total Property, Plant and Equipment	18,221.0	17,781.2
Accumulated Depreciation and Amortization	5,547.0	5,402.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	12,674.0	12,379.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	891.7	1,058.6
Securitized Assets	146.5	159.6
Employee Benefits and Pension Assets	161.9	152.9
Operating Lease Assets	67.9	73.6
Deferred Charges and Other Noncurrent Assets	123.4	138.7
TOTAL OTHER NONCURRENT ASSETS	1,391.4	1,583.4
TOTAL ASSETS	$ 15,458.0	$ 15,222.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2023 and December 31, 2022
(Unaudited)

	June 30, 2023	December 31, 2022
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 266.1	$ 182.2
Accounts Payable:		
General	324.3	451.2
Affiliated Companies	114.2	142.7
Long-term Debt Due Within One Year – Nonaffiliated	538.3	251.8
Risk Management Liabilities	1.1	3.6
Customer Deposits	75.3	75.1
Accrued Taxes	101.8	101.0
Accrued Interest	60.0	57.9
Obligations Under Operating Leases	14.3	15.0
Other Current Liabilities	108.6	109.7
TOTAL CURRENT LIABILITIES	1,604.0	1,390.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	5,061.4	5,158.7
Deferred Income Taxes	2,007.9	1,992.2
Regulatory Liabilities and Deferred Investment Tax Credits	1,094.5	1,143.6
Asset Retirement Obligations	419.7	419.2
Employee Benefits and Pension Obligations	33.7	34.2
Obligations Under Operating Leases	54.0	59.1
Deferred Credits and Other Noncurrent Liabilities	49.7	49.6
TOTAL NONCURRENT LIABILITIES	8,720.9	8,856.6
TOTAL LIABILITIES	10,324.9	10,246.8
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	3,046.5	2,891.1
Accumulated Other Comprehensive Income (Loss)	(6.8)	(4.8)
TOTAL COMMON SHAREHOLDER'S EQUITY	5,133.1	4,975.4
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 15,458.0	$ 15,222.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Six Months Ended June 30, 2023	2022
OPERATING ACTIVITIES		
Net Income	$ 155.4	$ 210.4
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	281.1	288.1
Deferred Income Taxes	(2.8)	17.1
Allowance for Equity Funds Used During Construction	(5.1)	(4.6)
Mark-to-Market of Risk Management Contracts	27.4	(38.5)
Deferred Fuel Over/Under-Recovery, Net	54.2	(312.1)
Change in Other Noncurrent Assets	7.7	(42.3)
Change in Other Noncurrent Liabilities	(39.3)	(0.2)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	60.4	65.4
Fuel, Materials and Supplies	(113.4)	(75.4)
Margin Deposits	(11.7)	64.5
Accounts Payable	(128.7)	162.8
Accrued Taxes, Net	13.4	(5.7)
Other Current Assets	5.1	0.7
Other Current Liabilities	(20.8)	(0.7)
Net Cash Flows from Operating Activities	282.9	329.5
INVESTING ACTIVITIES		
Construction Expenditures	(558.2)	(450.8)
Change in Advances to Affiliates, Net	0.9	1.4
Other Investing Activities	2.7	23.3
Net Cash Flows Used for Investing Activities	(554.6)	(426.1)
FINANCING ACTIVITIES		
Capital Contribution from Parent	4.3	2.8
Issuance of Long-term Debt – Nonaffiliated	200.0	103.3
Change in Advances from Affiliates, Net	83.9	149.9
Retirement of Long-term Debt – Nonaffiliated	(13.0)	(117.1)
Principal Payments for Finance Lease Obligations	(4.1)	(4.0)
Dividends Paid on Common Stock	—	(37.5)
Other Financing Activities	0.6	0.2
Net Cash Flows from Financing Activities	271.7	97.6
Net Increase in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	—	1.0
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	21.9	20.1
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 21.9	$ 21.1
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 125.9	$ 104.9
Net Cash Paid for Income Taxes	23.4	1.0
Noncash Acquisitions Under Finance Leases	1.7	0.5
Construction Expenditures Included in Current Liabilities as of June 30,	139.6	121.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in millions of KWhs)			
Retail:				
Residential	1,114	1,249	2,577	2,788
Commercial	1,207	1,165	2,396	2,284
Industrial	1,821	1,922	3,625	3,712
Miscellaneous	11	11	27	27
Total Retail	4,153	4,347	8,625	8,811
Wholesale	1,547	1,228	2,964	3,185
Total KWhs	5,700	5,575	11,589	11,996

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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in degree days)			
Actual – Heating (a)	227	268	1,914	2,508
Normal – Heating (b)	241	242	2,423	2,413
Actual – Cooling (c)	206	344	206	344
Normal – Cooling (b)	268	261	269	262

(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.

Indiana Michigan Power Company and Subsidiaries
Reconciliation of 2022 to 2023 Net Income
(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
2022 Net Income	$	67.2	$	156.7
Changes in Gross Margin:				
Retail Margins		9.9		50.2
Margins from Off-system Sales		8.9		23.6
Transmission Revenues		(8.9)		(12.6)
Other Revenues		(2.2)		2.8
Total Change in Gross Margin		7.7		64.0
Changes in Expenses and Other:				
Other Operation and Maintenance		(17.2)		(55.2)
Depreciation and Amortization		22.7		32.4
Taxes Other Than Income Taxes		8.0		13.7
Other Income		0.6		(1.4)
Non-Service Cost Components of Net Periodic Benefit Cost		1.5		3.2
Interest Expense		(4.8)		(7.7)
Total Change in Expenses and Other		10.8		(15.0)
Income Tax Expense		(10.9)		(28.1)
2023 Net Income	$	74.8	$	177.6

Second Quarter of 2023 Compared to Second Quarter of 2022

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 $13 million increase in deferred fuel primarily due to recoverable PJM expenses that are offset below.
  - A $10 million increase due to a reduction in provision for refund offset by lower wholesale true-ups.

  These increases were partially offset by:
  - A $14 million decrease in weather-related usage primarily due to a 40% decrease in cooling degree days.
- **Margins from Off-system Sales** increased $9 million primarily due to Rockport Plant, Unit 2 merchant operations activity.
- **Transmission Revenues** decreased $9 million primarily due to transmission formula rate true-up activity.

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

- **Other Operation and Maintenance** expenses increased $17 million primarily due to the following:
  - A $7 million increase in Transmission Expenses primarily due to transmission formula rate true-up activity.
  - A $7 million increase in Demand Side Management Rider expenses primarily due to an increase in revenues collected from customers.This increase was partially offset in Retail Margins above.
- **Depreciation and Amortization** expenses decreased $23 million primarily due to the expiration of the Rockport Plant, Unit 2 lease in December 2022, partially offset by an increase in depreciation expense due to the acquisition of Rockport Plant, Unit 2 at the end of the lease.

- **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.
- **Interest Expense** increased $5 million primarily due to higher long-term debt balances and higher interest rates.
- **Income Tax Expense** increased $11 million primarily due to the following:
  - A $6 million decrease in amortization of Excess ADIT.
  - A $4 million increase due to higher pretax book income.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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 $50 million primarily due to the following:
  - A $25 million increase in weather-normalized margins primarily in the residential and commercial classes, offset by a decrease in the wholesale class.
  - A $21 million increase due to a reduction in provision for refund partially offset by lower wholesale true-ups.
  - A $17 million increase due to a base rate revenue increase in Indiana and rider increases. This increase is partially offset in other expense items below.
  - A $13 million increase in deferred fuel primarily due to recoverable PJM expenses that are offset below.

  These increases were partially offset by:
  - A $32 million decrease in weather-related usage primarily due to a 24% decrease in heating degree days and a 40% decrease in cooling degree days.
- **Margins from Off-system Sales** increased $24 million primarily due to Rockport Plant, Unit 2 merchant operations activity and estimated PJM performance incentives for Rockport Plant, Unit 2 merchant operations related to winter storm Elliott in December 2022.
- **Transmission Revenues** decreased $13 million primarily due to transmission formula rate true-up activity.

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

- **Other Operation and Maintenance** expenses increased $55 million primarily due to the following:
  - A $16 million increase in Demand Side Management Rider expenses primarily due to an increase in revenues collected from customers. This increase was partially offset in Retail Margins above.
  - A $10 million increase in nuclear expenses at Cook Plant primarily due to refueling outage expenses.
  - A $9 million increase due to a decreased Nuclear Electric Insurance Limited distribution in 2023.
  - An $8 million increase in transmission expenses primarily due to transmission formula rate true-up activity.
- **Depreciation and Amortization** expenses decreased $32 million primarily due to the expiration of the Rockport Plant, Unit 2 lease in December 2022, partially offset by an increase in depreciation expense due to the acquisition of Rockport Plant, Unit 2 at the end of the lease and an increase in depreciable base.
- **Taxes Other Than Income Taxes** decreased $14 million primarily due to the repeal of the Indiana Utility Receipts Tax in July 2022. This decrease was partially offset in Retail Margins above.
- **Interest Expense** increased $8 million primarily due to higher long-term debt balances and higher interest rates.
- **Income Tax Expense** increased $28 million primarily due to the following:
  - A $12 million decrease in amortization of Excess ADIT.
  - A $10 million increase due to higher pretax book income.
  - A $4 million increase in state taxes.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
REVENUES				
Electric Generation, Transmission and Distribution	$ 580.4	$ 604.4	$ 1,223.2	$ 1,216.4
Sales to AEP Affiliates	1.9	7.1	3.1	9.1
Other Revenues – Affiliated	14.5	16.7	30.4	25.1
Other Revenues – Nonaffiliated	2.4	2.8	5.5	5.6
TOTAL REVENUES	599.2	631.0	1,262.2	1,256.2
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	93.9	110.9	193.1	216.6
Purchased Electricity from AEP Affiliates	37.1	59.6	82.2	116.7
Other Operation	170.1	149.2	339.8	288.5
Maintenance	57.1	60.8	115.7	111.8
Depreciation and Amortization	111.0	133.7	236.2	268.6
Taxes Other Than Income Taxes	20.6	28.6	40.1	53.8
TOTAL EXPENSES	489.8	542.8	1,007.1	1,056.0
OPERATING INCOME	109.4	88.2	255.1	200.2
Other Income (Expense):				
Other Income	3.0	2.4	3.6	5.0
Non-Service Cost Components of Net Periodic Benefit Cost	7.7	6.2	15.7	12.5
Interest Expense	(35.8)	(31.0)	(69.0)	(61.3)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	84.3	65.8	205.4	156.4
Income Tax Expense (Benefit)	9.5	(1.4)	27.8	(0.3)
NET INCOME	$ 74.8	$ 67.2	$ 177.6	$ 156.7

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	**2022**	**2023**	**2022**
Net Income	$ 74.8	$ 67.2	$ 177.6	$ 156.7
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0.1 for the Three Months Ended June 30, 2023 and 2022, Respectively, and $(0.2) and $0.2 for the Six Months Ended June 30, 2023 and 2022, Respectively	0.1	0.4	(0.6)	0.8
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $0 for the Three Months Ended June 30, 2023 and 2022, Respectively, and $(0.6) and $0 for the Six Months Ended June 30, 2023 and 2022, Respectively	(0.3)	(0.1)	(2.2)	(0.2)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(0.2)	0.3	(2.8)	0.6
TOTAL COMPREHENSIVE INCOME	$ 74.6	$ 67.5	$ 174.8	$ 157.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2022	$ 56.6	$ 988.8	$ 1,963.2	$ (0.3)	$ 3,008.3
Common Stock Dividends			(31.2)		(31.2)
Net Income			102.8		102.8
Other Comprehensive Loss				(2.6)	(2.6)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2023	56.6	988.8	2,034.8	(2.9)	3,077.3
Capital Contribution from Parent		0.1			0.1
Common Stock Dividends			(31.3)		(31.3)
Net Income			74.8		74.8
Other Comprehensive Loss				(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2023	$ 56.6	$ 988.9	$ 2,078.3	$ (3.1)	$ 3,120.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2023 and December 31, 2022
(in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.8	$ 4.2
Advances to Affiliates	40.5	23.0
Accounts Receivable:		
Customers	48.9	96.6
Affiliated Companies	113.3	104.0
Accrued Unbilled Revenues	0.8	0.6
Miscellaneous	6.6	4.7
Allowance for Uncollectible Accounts	(0.1)	(0.1)
Total Accounts Receivable	169.5	205.8
Fuel	85.6	46.5
Materials and Supplies	201.7	188.1
Risk Management Assets	21.4	15.2
Regulatory Asset for Under-Recovered Fuel Costs	17.5	47.1
Prepayments and Other Current Assets	44.1	41.9
TOTAL CURRENT ASSETS	584.1	571.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,598.9	5,585.1
Transmission	1,871.5	1,842.2
Distribution	3,131.7	3,024.7
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	831.6	839.3
Construction Work in Progress	292.0	253.0
Total Property, Plant and Equipment	11,725.7	11,544.3
Accumulated Depreciation, Depletion and Amortization	4,243.0	4,132.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,482.7	7,411.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	392.1	459.6
Spent Nuclear Fuel and Decommissioning Trusts	3,648.8	3,341.2
Operating Lease Assets	59.3	64.3
Deferred Charges and Other Noncurrent Assets	273.2	270.5
TOTAL OTHER NONCURRENT ASSETS	4,373.4	4,135.6
TOTAL ASSETS	$ 12,440.2	$ 12,118.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2023 and December 31, 2022
(dollars in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 249.9
Accounts Payable:		
General	220.8	173.4
Affiliated Companies	89.3	121.5
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2023 and December 31, 2022 Amounts Include $72.1 and $89.6, Respectively, Related to DCC Fuel)	74.3	341.8
Customer Deposits	50.4	48.6
Accrued Taxes	100.2	103.2
Accrued Interest	42.1	36.9
Obligations Under Operating Leases	16.5	16.0
Other Current Liabilities	84.6	105.8
TOTAL CURRENT LIABILITIES	678.2	1,197.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,389.8	2,919.0
Deferred Income Taxes	1,182.6	1,157.0
Regulatory Liabilities and Deferred Investment Tax Credits	1,909.5	1,702.2
Asset Retirement Obligations	2,064.9	2,027.6
Obligations Under Operating Leases	43.5	48.9
Deferred Credits and Other Noncurrent Liabilities	51.0	58.8
TOTAL NONCURRENT LIABILITIES	8,641.3	7,913.5
TOTAL LIABILITIES	9,319.5	9,110.6
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	988.9	988.8
Retained Earnings	2,078.3	1,963.2
Accumulated Other Comprehensive Income (Loss)	(3.1)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,120.7	3,008.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,440.2	$ 12,118.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
OPERATING ACTIVITIES		
Net Income	$ 177.6	$ 156.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	236.2	268.6
Deferred Income Taxes	(1.9)	0.3
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	36.7	(38.3)
Allowance for Equity Funds Used During Construction	(2.8)	(5.4)
Mark-to-Market of Risk Management Contracts	(13.7)	(11.6)
Amortization of Nuclear Fuel	50.2	39.0
Deferred Fuel Over/Under-Recovery, Net	29.6	(17.5)
Change in Other Noncurrent Assets	(7.0)	3.3
Change in Other Noncurrent Liabilities	(4.6)	22.2
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	37.3	24.0
Fuel, Materials and Supplies	(52.7)	4.5
Accounts Payable	46.8	13.6
Accrued Taxes, Net	(3.0)	(2.4)
Other Current Assets	(3.6)	15.2
Other Current Liabilities	(23.4)	(20.1)
Net Cash Flows from Operating Activities	501.7	452.1
INVESTING ACTIVITIES		
Construction Expenditures	(267.1)	(262.5)
Change in Advances to Affiliates, Net	(17.5)	(1.0)
Purchases of Investment Securities	(1,233.3)	(1,253.2)
Sales of Investment Securities	1,206.3	1,229.9
Acquisitions of Nuclear Fuel	(73.9)	(67.7)
Other Investing Activities	3.3	3.0
Net Cash Flows Used for Investing Activities	(382.2)	(351.5)
FINANCING ACTIVITIES		
Capital Contribution from Parent	0.1	1.3
Issuance of Long-term Debt – Nonaffiliated	494.9	72.8
Change in Advances from Affiliates, Net	(249.9)	(42.8)
Retirement of Long-term Debt – Nonaffiliated	(299.2)	(40.7)
Principal Payments for Finance Lease Obligations	(3.8)	(40.1)
Dividends Paid on Common Stock	(62.5)	(50.0)
Other Financing Activities	0.5	0.4
Net Cash Flows Used for Financing Activities	(119.9)	(99.1)
Net Increase (Decrease) in Cash and Cash Equivalents	(0.4)	1.5
Cash and Cash Equivalents at Beginning of Period	4.2	1.3
Cash and Cash Equivalents at End of Period	$ 3.8	$ 2.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 62.1	$ 59.2
Net Cash Paid (Received) for Income Taxes	13.8	(4.9)
Noncash Acquisitions Under Finance Leases	3.2	0.4
Construction Expenditures Included in Current Liabilities as of June 30,	78.1	68.2
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	(36.0)	—

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

OHIO POWER COMPANY AND SUBSIDIARIES

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in millions of KWhs)			
Retail:				
Residential	2,828	3,058	6,562	7,192
Commercial	3,950	3,850	7,950	7,701
Industrial	3,502	3,624	6,920	7,127
Miscellaneous	24	24	54	54
Total Retail (a)	10,304	10,556	21,486	22,074
Wholesale (b)	428	565	881	1,136
Total KWhs	10,732	11,121	22,367	23,210

(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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in degree days)			
Actual – Heating (a)	177	206	1,521	2,070
Normal – Heating (b)	185	186	2,076	2,072
Actual – Cooling (c)	184	359	184	360
Normal – Cooling (b)	305	298	308	301

(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.

Ohio Power Company and Subsidiaries
Reconciliation of 2022 to 2023 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2022 Net Income	$ 74.8	$ 158.0
Changes in Gross Margin:		
Retail Margins	13.7	34.2
Margins from Off-system Sales	17.3	41.4
Transmission Revenues	2.0	1.1
Other Revenues	(3.3)	(2.4)
Total Change in Gross Margin	29.7	74.3
Changes in Expenses and Other:		
Other Operation and Maintenance	(44.8)	(84.9)
Depreciation and Amortization	3.1	2.8
Taxes Other Than Income Taxes	6.8	(1.5)
Other Income	(0.4)	(0.5)
Allowance for Equity Funds Used During Construction	(0.5)	(0.7)
Non-Service Cost Components of Net Periodic Benefit Cost	1.0	2.0
Interest Expense	(2.1)	(4.0)
Total Change in Expenses and Other	(36.9)	(86.8)
Income Tax Expense	0.9	1.0
Equity Earnings of Unconsolidated Subsidiaries	(0.8)	(0.8)
2023 Net Income	$ 67.7	$ 145.7

Second Quarter of 2023 Compared to Second Quarter of 2022

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 $14 million primarily due to the following:
  - A $19 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 $14 million increase due to various rider revenues. This increase was partially offset in Margins from Off-system Sales and other expense items below.

  These increases were partially offset by:
  - A $13 million decrease in weather-related usage due to a 49% decrease in cooling degree days.
  - A $7 million decrease in weather-normalized margins primarily in the residential and commercial classes.
- **Margins from Off-system Sales** increased $17 million primarily due to the following:
  - A $51 million increase in deferrals of OVEC costs. This increase was offset in Retail Margins above.

This increase was partially offset by:
  - A $33 million decrease in off-system sales at OVEC due to lower market prices and volume.This decrease was offset in Retail Margins above.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $45 million primarily due to the following:
  - A $19 million increase related to an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.
  - An $18 million increase in transmission expenses primarily due to:
    - A $15 million increase in transmission formula rate true-up activity.
    - A $12 million increase in recoverable PJM expense. This increase was offset in Retail Margins above.

    These increases were partially offset by:
    - A $6 million decrease in vegetation management expenses.
  - A $6 million increase in distribution expenses primarily related to vegetation management. This increase was offset in Retail Margins above.

  These increases were partially offset by:
  - A $5 million decrease in employee-related expenses.
- **Depreciation and Amortization** expenses decreased $3 million primarily due to the following:
  - A $13 million decrease in recoverable Distribution Investment Rider depreciable expenses. This decrease was offset in Retail Margins above.

  This decrease was partially offset by:
  - An $8 million increase due to a higher depreciable base.
- **Taxes Other Than Income Taxes** decreased $7 million due to favorable property tax true-up activity.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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 $34 million primarily due to the following:
  - A $43 million increase due to various rider revenues. This increase was partially offset in Margins from Off-system Sales and other expense items below.
  - A $34 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.

  These increases were partially offset by:
  - A $38 million decrease in weather-related usage due to a 27% decrease in heating degree days and a 49% decrease in cooling degree days.
- **Margins from Off-system Sales** increased $41 million due to the following:
  - An $84 million increase in deferrals of OVEC costs. This increase was offset in Retail Margins above.

  This increase was partially offset by:
  - A $43 million decrease in off-system sales at OVEC due to lower market prices and volume.This decrease was offset in Retail Margins above.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $85 million primarily due to the following:
  - A $48 million increase related to an energy assistance program for qualified Ohio customers. This increase was offset in Retail Margins above.
  - A $23 million increase in transmission expenses primarily due to:
    - A $17 million increase in recoverable PJM expenses. This increase was offset in Retail Margins above.
    - A $16 million increase in transmission formula rate true-up activity.

    These increases were partially offset by:
    - A $7 million decrease in vegetation management expenses.

  - An $8 million increase in distribution expenses related to vegetation management. This increase was offset in Retail Margins above.

  These increases were partially offset by:
  - A $9 million decrease in employee-related expenses.
- **Depreciation and Amortization** expenses decreased $3 million primarily due to the following:
  - A $21 million decrease in recoverable Distribution Investment Rider depreciable expenses. This decrease was offset in Retail Margins above.

  This decrease was partially offset by:
  - A $13 million increase due to a higher depreciable base.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
REVENUES				
Electricity, Transmission and Distribution	$ 868.8	$ 817.2	$ 1,890.6	$ 1,641.4
Sales to AEP Affiliates	8.2	3.9	15.8	7.6
Other Revenues	2.1	1.8	7.3	3.9
TOTAL REVENUES	879.1	822.9	1,913.7	1,652.9
EXPENSES				
Purchased Electricity for Resale	267.6	249.2	660.2	475.5
Purchased Electricity from AEP Affiliates	11.6	3.5	11.6	9.8
Other Operation	265.4	223.3	539.2	460.9
Maintenance	51.2	48.5	95.5	88.9
Depreciation and Amortization	68.2	71.3	143.4	146.2
Taxes Other Than Income Taxes	114.2	121.0	249.5	248.0
TOTAL EXPENSES	778.2	716.8	1,699.4	1,429.3
OPERATING INCOME	100.9	106.1	214.3	223.6
Other Income (Expense):				
Other Income	0.2	0.6	0.3	0.8
Allowance for Equity Funds Used During Construction	2.9	3.4	5.7	6.4
Non-Service Cost Components of Net Periodic Benefit Cost	6.5	5.5	13.0	11.0
Interest Expense	(31.9)	(29.8)	(63.0)	(59.0)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	78.6	85.8	170.3	182.8
Income Tax Expense	10.9	11.8	24.6	25.6
Equity Earnings of Unconsolidated Subsidiaries	—	0.8	—	0.8
NET INCOME	$ 67.7	$ 74.8	$ 145.7	$ 158.0

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 321.2	$ 837.8	$ 1,929.1	$ 3,088.1
Capital Contribution from Parent		50.0		50.0
Net Income			78.0	78.0
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2023	321.2	887.8	2,007.1	3,216.1
Capital Contribution from Parent		125.0		125.0
Net Income			67.7	67.7
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2023	$ 321.2	$ 1,012.8	$ 2,074.8	$ 3,408.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2023 and December 31, 2022
(in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents	$ 9.7	$ 9.6
Accounts Receivable:		
Customers	106.0	119.9
Affiliated Companies	126.5	100.9
Accrued Unbilled Revenues	—	17.8
Miscellaneous	0.4	0.1
Allowance for Uncollectible Accounts	—	(0.1)
Total Accounts Receivable	232.9	238.6
Materials and Supplies	139.3	109.5
Renewable Energy Credits	28.9	35.0
Prepayments and Other Current Assets	15.8	21.7
TOTAL CURRENT ASSETS	426.6	414.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	3,274.0	3,198.6
Distribution	6,633.3	6,450.3
Other Property, Plant and Equipment	1,071.3	1,051.4
Construction Work in Progress	651.3	474.3
Total Property, Plant and Equipment	11,629.9	11,174.6
Accumulated Depreciation and Amortization	2,627.0	2,565.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,002.9	8,609.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	406.9	327.3
Operating Lease Assets	71.0	73.8
Deferred Charges and Other Noncurrent Assets	363.3	578.3
TOTAL OTHER NONCURRENT ASSETS	841.2	979.4
TOTAL ASSETS	$ 10,270.7	$ 10,003.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2023 and December 31, 2022
(Unaudited)

	June 30, 2023	December 31, 2022
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 72.3	$ 172.9
Accounts Payable:		
General	322.6	337.3
Affiliated Companies	153.5	126.1
Long-term Debt Due Within One Year – Nonaffiliated	—	0.1
Risk Management Liabilities	6.3	1.8
Customer Deposits	59.5	96.5
Accrued Taxes	441.8	733.1
Obligations Under Operating Leases	13.5	13.5
Other Current Liabilities	158.5	154.2
TOTAL CURRENT LIABILITIES	1,228.0	1,635.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,365.6	2,970.2
Long-term Risk Management Liabilities	47.7	37.9
Deferred Income Taxes	1,123.4	1,101.1
Regulatory Liabilities and Deferred Investment Tax Credits	992.6	1,044.0
Obligations Under Operating Leases	57.8	60.3
Deferred Credits and Other Noncurrent Liabilities	46.8	66.0
TOTAL NONCURRENT LIABILITIES	5,633.9	5,279.5
TOTAL LIABILITIES	6,861.9	6,915.0
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	1,012.8	837.8
Retained Earnings	2,074.8	1,929.1
TOTAL COMMON SHAREHOLDER'S EQUITY	3,408.8	3,088.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,270.7	$ 10,003.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
OPERATING ACTIVITIES		
Net Income	$ 145.7	$ 158.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	143.4	146.2
Deferred Income Taxes	7.1	13.8
Allowance for Equity Funds Used During Construction	(5.7)	(6.4)
Mark-to-Market of Risk Management Contracts	14.3	(44.3)
Property Taxes	193.9	178.6
Change in Other Noncurrent Assets	(88.0)	(53.1)
Change in Other Noncurrent Liabilities	(37.7)	44.3
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	8.2	(35.8)
Materials and Supplies	(2.5)	(10.1)
Accounts Payable	30.8	78.2
Customer Deposits	(37.0)	142.5
Accrued Taxes, Net	(289.9)	(246.8)
Other Current Assets	2.3	12.2
Other Current Liabilities	(15.3)	35.6
Net Cash Flows from Operating Activities	69.6	412.9
INVESTING ACTIVITIES		
Construction Expenditures	(547.7)	(376.4)
Change in Advances to Affiliates, Net	—	(14.0)
Other Investing Activities	11.1	12.6
Net Cash Flows Used for Investing Activities	(536.6)	(377.8)
FINANCING ACTIVITIES		
Capital Contribution from Parent	175.0	0.7
Issuance of Long-term Debt – Nonaffiliated	395.1	—
Change in Advances from Affiliates, Net	(100.6)	—
Retirement of Long-term Debt – Nonaffiliated	(0.6)	(0.1)
Principal Payments for Finance Lease Obligations	(2.4)	(2.4)
Dividends Paid on Common Stock	—	(30.0)
Other Financing Activities	0.6	0.6
Net Cash Flows from (Used for) Financing Activities	467.1	(31.2)
Net Increase in Cash and Cash Equivalents	0.1	3.9
Cash and Cash Equivalents at Beginning of Period	9.6	3.0
Cash and Cash Equivalents at End of Period	$ 9.7	$ 6.9
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 57.6	$ 56.8
Net Cash Paid for Income Taxes	9.2	21.4
Noncash Acquisitions Under Finance Leases	2.1	1.2
Construction Expenditures Included in Current Liabilities as of June 30,	87.4	92.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in millions of KWhs)			
Retail:				
Residential	1,358	1,469	2,746	3,027
Commercial	1,291	1,309	2,395	2,429
Industrial	1,507	1,565	2,946	2,951
Miscellaneous	317	333	592	616
Total Retail	4,473	4,676	8,679	9,023
Wholesale	46	262	73	605
Total KWhs	4,519	4,938	8,752	9,628

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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in degree days)			
Actual – Heating (a)	28	19	899	1,153
Normal – Heating (b)	45	45	1,100	1,085
Actual – Cooling (c)	638	786	648	797
Normal – Cooling (b)	660	650	677	667

(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.

Public Service Company of Oklahoma
Reconciliation of 2022 to 2023 Net Income
(in millions)

		Three Months Ended June 30,		Six Months Ended June 30,
2022 Net Income	$	43.0	$	48.8
Changes in Gross Margin:				
Retail Margins (a)		0.8		16.1
Transmission Revenues		0.3		1.9
Other Revenues		(0.5)		0.6
Total Change in Gross Margin		0.6		18.6
Changes in Expenses and Other:				
Other Operation and Maintenance		11.2		4.5
Depreciation and Amortization		(4.4)		(12.8)
Taxes Other Than Income Taxes		(1.2)		(4.3)
Interest Income		(2.4)		(3.1)
Allowance for Equity Funds Used During Construction		1.2		1.6
Non-Service Cost Components of Net Periodic Benefit Cost		0.3		0.8
Interest Expense		(5.5)		(11.8)
Total Change in Expenses and Other		(0.8)		(25.1)
Income Tax Benefit		8.2		6.4
2023 Net Income	$	51.0	$	48.7

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

Second Quarter of 2023 Compared to Second Quarter of 2022

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 $1 million primarily due to the following:
  - A $9 million increase in base rate and rider revenues. This increase was partially offset in other expense items below.
  - A $4 million increase in fuel revenue due to increased carrying charges on fuel under-recovered balances.
  - A $3 million increase in weather-normalized margins primarily in the residential and commercial classes.

  These increases were partially offset by:
  - An $8 million decrease in weather-related usage primarily due to a 19% decrease in cooling degree days.
  - A $7 million decrease in deferred fuel primarily due to an increase in PTCs. This decrease was offset in Income Tax Benefit below.

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

- **Other Operation and Maintenance** expenses decreased $11 million primarily due to the following:
  - A $5 million decrease due to the capitalization of previously expensed renewable generation pre-construction charges.
  - A $4 million decrease in transmission expenses primarily due to a decrease in recoverable SPP transmission expense. The recoverable SPP transmission expense was offset in Retail Margins above.
- **Interest Expense** increased $6 million primarily due to higher long-term debt balances and higher interest rates.
- **Income Tax Benefit** increased $8 million primarily due to an increase in PTCs. The increase in PTCs was partially offset in Retail Margins above.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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 $16 million primarily due to the following:
  - An $18 million increase in base rate and rider revenues. This increase was partially offset in other expense items below.
  - An $8 million increase in fuel revenue due to increased carrying charges on fuel under-recovered balances.
  - A $5 million increase in weather-normalized margins primarily in the residential and commercial classes.

  These increases were partially offset by:
  - An $11 million decrease in weather-related usage primarily due to a 19% decrease in cooling degree days and a 22% decrease in heating degree days.
  - A $4 million decrease in deferred fuel primarily due to an increase in PTCs. This decrease was offset in Income Tax Benefit below.

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

- **Other Operation and Maintenance** expenses decreased $5 million primarily due to the following:
  - A $5 million decrease due to the capitalization of previously expensed renewable generation pre-construction charges.
  - A $5 million decrease in transmission expenses due to a $15 million decrease in recoverable SPP transmission expense partially offset by a $10 million increase due to a change in rider recovery. The recoverable SPP transmission expense was offset in Retail Margins above.

  These decreases were partially offset by:
  - A $3 million increase in generation maintenance expenses at various plants.
- **Depreciation and Amortization** expenses increased $13 million primarily due to a higher depreciable base, implementation of new rates and the timing of refunds to customers under rate rider mechanisms.
- **Interest Expense** increased $12 million primarily due to higher long-term debt balances and higher interest rates.
- **Income Tax Benefit** increased $6 million primarily due to an increase in PTCs. The increase in PTCs was partially offset in Retail Margins above.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
REVENUES				
Electric Generation, Transmission and Distribution	$ 472.4	$ 440.0	$ 887.2	$ 826.4
Sales to AEP Affiliates	0.1	0.8	0.8	1.4
Other Revenues	2.2	2.1	3.7	2.7
TOTAL REVENUES	474.7	442.9	891.7	830.5
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	223.1	191.9	423.2	380.6
Other Operation	87.5	95.9	179.6	184.7
Maintenance	28.5	31.3	57.3	56.7
Depreciation and Amortization	64.9	60.5	126.0	113.2
Taxes Other Than Income Taxes	15.0	13.8	32.3	28.0
TOTAL EXPENSES	419.0	393.4	818.4	763.2
OPERATING INCOME	55.7	49.5	73.3	67.3
Other Income (Expense):				
Interest Income	0.1	2.5	1.1	4.2
Allowance for Equity Funds Used During Construction	1.4	0.2	2.9	1.3
Non-Service Cost Components of Net Periodic Benefit Cost	3.5	3.2	7.1	6.3
Interest Expense	(26.8)	(21.3)	(52.0)	(40.2)
INCOME BEFORE INCOME TAX BENEFIT	33.9	34.1	32.4	38.9
Income Tax Benefit	(17.1)	(8.9)	(16.3)	(9.9)
NET INCOME	$ 51.0	$ 43.0	$ 48.7	$ 48.8

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	**2022**	**2023**	**2022**
Net Income	$ 51.0	$ 43.0	$ 48.7	$ 48.8
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2023 and 2022, Respectively, and $(0.4) and $0 for the Six Months Ended June 30, 2023 and 2022, Respectively	—	—	(1.5)	—
TOTAL COMPREHENSIVE INCOME	$ 51.0	$ 43.0	$ 47.2	$ 48.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER’S EQUITY
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 157.2	$ 1,042.6	$ 1,218.0	$ 1.3	$ 2,419.1
ommon Stock Dividends			(17.5)		(17.5)
et Loss			(2.3)		(2.3)
ther Comprehensive Loss				(1.5)	(1.5)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2023	157.2	1,042.6	1,198.2	(0.2)	2,397.8
eturn of Capital to Parent		(2.5)			(2.5)
et Income			51.0		51.0
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2023	$ 157.2	$ 1,040.1	$ 1,249.2	$ (0.2)	$ 2,446.3

e Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2023 and December 31, 2022
(in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4.6	$ 4.0
Accounts Receivable:		
Customers	80.5	70.1
Affiliated Companies	67.1	52.2
Miscellaneous	0.5	0.8
Total Accounts Receivable	148.1	123.1
Fuel	20.6	11.6
Materials and Supplies	105.8	111.1
Risk Management Assets	44.8	25.3
Accrued Tax Benefits	39.0	16.1
Regulatory Asset for Under-Recovered Fuel Costs	178.7	178.7
Prepayments and Other Current Assets	22.8	21.6
TOTAL CURRENT ASSETS	564.4	491.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	2,675.7	2,394.8
Transmission	1,182.7	1,164.4
Distribution	3,309.0	3,216.4
Other Property, Plant and Equipment	492.7	469.3
Construction Work in Progress	295.2	219.3
Total Property, Plant and Equipment	7,955.3	7,464.2
Accumulated Depreciation and Amortization	2,011.0	1,837.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	5,944.3	5,626.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	570.0	653.7
Employee Benefits and Pension Assets	70.0	67.3
Operating Lease Assets	114.9	106.1
Deferred Charges and Other Noncurrent Assets	50.4	20.8
TOTAL OTHER NONCURRENT ASSETS	805.3	847.9
TOTAL ASSETS	$ 7,314.0	$ 6,965.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2023 and December 31, 2022
(Unaudited)

	June 30, 2023	December 31, 2022
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 68.1	$ 364.2
Accounts Payable:		
General	284.2	202.9
Affiliated Companies	85.4	76.7
Long-term Debt Due Within One Year – Nonaffiliated	0.6	0.5
Customer Deposits	60.0	59.0
Accrued Taxes	60.5	28.7
Obligations Under Operating Leases	9.5	8.9
Other Current Liabilities	95.5	101.8
TOTAL CURRENT LIABILITIES	663.8	842.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,383.3	1,912.3
Deferred Income Taxes	815.7	788.6
Regulatory Liabilities and Deferred Investment Tax Credits	797.1	809.1
Asset Retirement Obligations	81.4	73.5
Obligations Under Operating Leases	108.4	99.3
Deferred Credits and Other Noncurrent Liabilities	18.0	21.3
TOTAL NONCURRENT LIABILITIES	4,203.9	3,704.1
TOTAL LIABILITIES	4,867.7	4,546.8
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	1,040.1	1,042.6
Retained Earnings	1,249.2	1,218.0
Accumulated Other Comprehensive Income (Loss)	(0.2)	1.3
TOTAL COMMON SHAREHOLDER'S EQUITY	2,446.3	2,419.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,314.0	$ 6,965.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
OPERATING ACTIVITIES		
Net Income	$ 48.7	$ 48.8
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	126.0	113.2
Deferred Income Taxes	13.1	(20.4)
Allowance for Equity Funds Used During Construction	(2.9)	(1.3)
Mark-to-Market of Risk Management Contracts	(19.3)	(56.2)
Property Taxes	(27.9)	(24.4)
Deferred Fuel Over/Under-Recovery, Net	146.3	(124.2)
Change in Other Regulatory Assets	(57.3)	4.8
Change in Other Noncurrent Assets	(22.7)	(12.2)
Change in Other Noncurrent Liabilities	(0.6)	10.4
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(25.0)	(30.6)
Fuel, Materials and Supplies	(2.6)	(10.8)
Accounts Payable	75.2	123.7
Accrued Taxes, Net	8.9	23.9
Other Current Assets	5.3	(16.8)
Other Current Liabilities	(8.4)	9.9
Net Cash Flows from Operating Activities	256.8	37.8
INVESTING ACTIVITIES		
Construction Expenditures	(263.6)	(200.2)
Acquisitions of Renewable Energy Facilities	(145.7)	(549.3)
Other Investing Activities	1.1	2.3
Net Cash Flows Used for Investing Activities	(408.2)	(747.2)
FINANCING ACTIVITIES		
Capital Contribution from Parent	—	2.2
Return of Capital to Parent	(2.5)	—
Issuance of Long-term Debt – Nonaffiliated	469.8	500.0
Change in Advances from Affiliates, Net	(296.1)	211.1
Retirement of Long-term Debt – Nonaffiliated	(0.3)	(0.3)
Principal Payments for Finance Lease Obligations	(1.7)	(1.6)
Dividends Paid on Common Stock	(17.5)	—
Other Financing Activities	0.3	0.3
Net Cash Flows from Financing Activities	152.0	711.7
Net Increase in Cash and Cash Equivalents	0.6	2.3
Cash and Cash Equivalents at Beginning of Period	4.0	1.3
Cash and Cash Equivalents at End of Period	$ 4.6	$ 3.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 37.6	$ 38.1
Net Cash Paid (Received) for Income Taxes	(6.1)	12.2
Noncash Acquisitions Under Finance Leases	1.2	1.1
Construction Expenditures Included in Current Liabilities as of June 30,	83.6	41.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in millions of KWhs)			
Retail:				
Residential	1,371	1,502	2,722	3,138
Commercial	1,412	1,488	2,580	2,754
Industrial	1,360	1,394	2,563	2,509
Miscellaneous	19	20	36	38
Total Retail	4,162	4,404	7,901	8,439
Wholesale	1,288	1,809	2,558	3,568
Total KWhs	5,450	6,213	10,459	12,007

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 June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in degree days)			
Actual – Heating (a)	12	10	413	704
Normal – Heating (b)	25	26	730	726
Actual – Cooling (c)	851	985	958	1,015
Normal – Cooling (b)	748	735	788	775

(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.

Reconciliation of 2022 to 2023
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2022 Earnings Attributable to Common Shareholder	$ 76.7	$ 120.8
Changes in Gross Margin:		
Retail Margins (a)	(7.8)	(3.4)
Margins from Off-system Sales	(0.7)	(2.3)
Transmission Revenues	(2.2)	5.1
Other Revenues	2.0	1.9
Total Change in Gross Margin	(8.7)	1.3
Changes in Expenses and Other:		
Other Operation and Maintenance	17.7	2.4
Depreciation and Amortization	(7.6)	(10.2)
Taxes Other Than Income Taxes	(1.2)	(7.5)
Interest Income	(2.3)	(0.5)
Allowance for Equity Funds Used During Construction	1.7	0.6
Non-Service Cost Components of Net Periodic Benefit Cost	0.3	0.6
Interest Expense	(6.4)	1.7
Total Change in Expenses and Other	2.2	(12.9)
Income Tax Benefit	9.0	10.8
Net Income Attributable to Noncontrolling Interest	1.8	1.6
2023 Earnings Attributable to Common Shareholder	$ 81.0	$ 121.6

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

Second Quarter of 2023 Compared to Second Quarter of 2022

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

- **Retail Margins** decreased $8 million primarily due to the following:
  - An $11 million decrease in weather-related usage primarily due to a 14% decrease in cooling degree days.
  - An $8 million decrease in fuel revenues due to an increase in Arkansas PTCs. This decrease was offset in Income Tax Benefit below.
  - A $3 million decrease in weather-normalized margins primarily in the industrial and commercial classes.

  These decreases were partially offset by:
  - A $14 million increase due to base rate revenue increases in Arkansas and Louisiana and rider increases in all retail jurisdictions. These increases were partially offset in other expense items below.

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

- **Other Operation and Maintenance** expenses decreased $18 million primarily due to the following:
  - An $11 million decrease due to the capitalization of previously expensed renewable generation pre-construction charges.
  - A $6 million decrease due to legislation passed in Texas in May 2023 allowing employee financially based incentives to be recovered.
- **Depreciation and Amortization** increased $8 million primarily due to an increase in amortization of regulatory assets, a higher depreciable base and the NCWF rider. This increase was partially offset in Retail Margins above.
- **Interest Expense** increased $6 million primarily due to a settlement agreement in Louisiana which provided for $4 million of carrying charges on storm-related regulatory assets.
- **Income Tax Benefit** increased $9 million primarily due to an increase in PTCs and a decrease in state taxes. The increase in PTCs was partially offset in Retail Margins above.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

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

- **Retail Margins** decreased $3 million primarily due to the following:
  - A $19 million decrease in weather-related usage primarily due to a 41% decrease in heating degree days and a 6% decrease in cooling degree days.
  - A $17 million decrease in weather-normalized margins primarily in the residential and wholesale classes.
  - A $3 million decrease in fuel revenues due to an increase in Arkansas PTCs, partially offset by an increase in carrying charges on under-recovered fuel balances.

  These decreases were partially offset by:
  - A $36 million increase primarily due to base rate revenue increases in Arkansas and Louisiana and rider increases in all retail jurisdictions. These increases were partially offset in other expense items below.
- **Transmission Revenues** increased $5 million primarily due to the reversal of a prior period provision for refund.

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

- **Other Operation and Maintenance** expenses decreased $2 million primarily due to the following:
  - A $9 million decrease due to the capitalization of previously expensed renewable generation pre-construction charges.
  - A $6 million decrease due to legislation passed in Texas in May 2023 allowing employee financially based incentives to be recovered.

  These decreases were partially offset by:
  - A $6 million increase in generation-related expenses.
  - A $6 million increase in accounts receivable factoring expenses primarily due to increased interest rates.
- **Depreciation and Amortization** expenses increased $10 million primarily due to an increase in amortization of regulatory assets. This increase was partially offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to increased property taxes driven by the investment in the NCWF.
- **Income Tax Benefit** increased $11 million primarily due to an increase in PTCs and a decrease in state tax expense. The increase in PTCs was partially offset in Retail Margins above.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
REVENUES				
Electric Generation, Transmission and Distribution	$ 522.5	$ 520.7	$ 1,026.2	$ 1,004.9
Sales to AEP Affiliates	14.5	15.5	26.2	25.5
Other Revenues	0.8	0.4	1.3	1.0
TOTAL REVENUES	537.8	536.6	1,053.7	1,031.4
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	189.9	180.0	399.2	378.2
Other Operation	85.2	103.1	184.4	194.6
Maintenance	45.0	44.8	82.7	74.9
Depreciation and Amortization	85.8	78.2	166.2	156.0
Taxes Other Than Income Taxes	32.1	30.9	68.2	60.7
TOTAL EXPENSES	438.0	437.0	900.7	864.4
OPERATING INCOME	99.8	99.6	153.0	167.0
Other Income (Expense):				
Interest Income	5.3	7.6	10.7	11.2
Allowance for Equity Funds Used During Construction	2.5	0.8	3.0	2.4
Non-Service Cost Components of Net Periodic Benefit Cost	3.4	3.1	6.8	6.2
Interest Expense	(40.1)	(33.7)	(65.1)	(66.8)
INCOME BEFORE INCOME TAX BENEFIT AND EQUITY EARNINGS	70.9	77.4	108.4	120.0
Income Tax Benefit	(10.0)	(1.0)	(14.0)	(3.2)
Equity Earnings of Unconsolidated Subsidiary	0.4	0.4	0.7	0.7
NET INCOME	81.3	78.8	123.1	123.9
Net Income Attributable to Noncontrolling Interest	0.3	2.1	1.5	3.1
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 81.0	$ 76.7	$ 121.6	$ 120.8

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	**2022**	**2023**	**2022**
Net Income	$ 81.3	$ 78.8	$ 123.1	$ 123.9
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2023 and 2022, Respectively, and $0.1 and $0 for the Six Months Ended June 30, 2023 and 2022, Respectively	(0.1)	(0.1)	0.3	—
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended June 30, 2023 and 2022, Respectively, and $(0.2) and $(0.2) for the Six Months Ended June 30, 2023 and 2022, Respectively	(0.3)	(0.4)	(0.6)	(0.8)
TOTAL OTHER COMPREHENSIVE LOSS	(0.4)	(0.5)	(0.3)	(0.8)
TOTAL COMPREHENSIVE INCOME	80.9	78.3	122.8	123.1
Total Comprehensive Income Attributable to Noncontrolling Interest	0.3	2.1	1.5	3.1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 80.6	$ 76.2	$ 121.3	$ 120.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2023 and 2022
(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, 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
TOTAL EQUITY – DECEMBER 31, 2022	$ 0.1	$ 1,442.2	$ 2,236.0	$ (4.2)	$ 0.7	$ 3,674.8
Capital Contribution from Parent		50.0				50.0
Common Stock Dividends – Nonaffiliated					(1.5)	(1.5)
Net Income			40.6		1.2	41.8
Other Comprehensive Income				0.1		0.1
TOTAL EQUITY – MARCH 31, 2023	0.1	1,492.2	2,276.6	(4.1)	0.4	3,765.2
Common Stock Dividends			(50.0)			(50.0)
Common Stock Dividends – Nonaffiliated					(0.6)	(0.6)
Net Income			81.0		0.3	81.3
Other Comprehensive Loss				(0.4)		(0.4)
TOTAL EQUITY – JUNE 30, 2023	$ 0.1	$ 1,492.2	$ 2,307.6	$ (4.5)	$ 0.1	$ 3,795.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2023 and December 31, 2022
(in millions)
(Unaudited)

	June 30, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents (June 30, 2023 and December 31, 2022 Amounts Include $0.2 and $84.2, Respectively, Related to Sabine)	$ 4.6	$ 88.4
Advances to Affiliates	2.2	2.1
Accounts Receivable:		
Customers	38.6	38.8
Affiliated Companies	63.6	65.4
Miscellaneous	16.7	10.4
Total Accounts Receivable	118.9	114.6
Fuel (June 30, 2023 and December 31, 2022 Amounts Include $0 and $14.2, Respectively, Related to Sabine)	96.7	81.3
Materials and Supplies (June 30, 2023 and December 31, 2022 Amounts Include $4.2 and $4.2, Respectively, Related to Sabine)	86.3	92.1
Risk Management Assets	28.0	16.4
Accrued Tax Benefits	43.8	16.5
Regulatory Asset for Under-Recovered Fuel Costs	213.6	353.0
Prepayments and Other Current Assets	18.0	47.8
TOTAL CURRENT ASSETS	612.1	812.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,887.9	5,476.2
Transmission	2,536.4	2,479.8
Distribution	2,739.4	2,659.6
Other Property, Plant and Equipment (June 30, 2023 and December 31, 2022 Amounts Include $187.8 and $219.8, Respectively, Related to Sabine)	800.0	804.4
Construction Work in Progress	516.9	369.5
Total Property, Plant and Equipment	11,480.6	11,789.5
Accumulated Depreciation and Amortization (June 30, 2023 and December 31, 2022 Amounts Include $187.8 and $212.5, Respectively, Related to Sabine)	3,007.7	3,527.3
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,472.9	8,262.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,147.2	1,042.4
Deferred Charges and Other Noncurrent Assets	313.9	262.0
TOTAL OTHER NONCURRENT ASSETS	1,461.1	1,304.4
TOTAL ASSETS	$ 10,546.1	$ 10,378.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2023 and December 31, 2022
(Unaudited)

	June 30, 2023	December 31, 2022
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 32.6	$ 310.7
Accounts Payable:		
General	260.2	213.1
Affiliated Companies	96.7	81.7
Short-term Debt – Nonaffiliated	3.9	—
Long-term Debt Due Within One Year – Nonaffiliated	—	6.2
Customer Deposits	71.0	65.4
Accrued Taxes	118.4	52.8
Accrued Interest	38.9	36.0
Obligations Under Operating Leases	9.2	8.4
Asset Retirement Obligations	43.7	43.7
Other Current Liabilities	110.1	129.7
TOTAL CURRENT LIABILITIES	784.7	947.7
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,645.6	3,385.4
Deferred Income Taxes	1,131.9	1,089.7
Regulatory Liabilities and Deferred Investment Tax Credits	766.8	825.7
Asset Retirement Obligations	225.5	237.2
Employee Benefits and Pension Obligations	29.8	29.7
Obligations Under Operating Leases	125.0	120.2
Deferred Credits and Other Noncurrent Liabilities	41.3	68.4
TOTAL NONCURRENT LIABILITIES	5,965.9	5,756.3
TOTAL LIABILITIES	6,750.6	6,704.0
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	1,492.2	1,442.2
Retained Earnings	2,307.6	2,236.0
Accumulated Other Comprehensive Income (Loss)	(4.5)	(4.2)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,795.4	3,674.1
Noncontrolling Interest	0.1	0.7
TOTAL EQUITY	3,795.5	3,674.8
TOTAL LIABILITIES AND EQUITY	$ 10,546.1	$ 10,378.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2023 and 2022
(in millions)
(Unaudited)

	Six Months Ended June 30, 2023	2022
OPERATING ACTIVITIES		
Net Income	$ 123.1	$ 123.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	166.2	156.0
Deferred Income Taxes	28.0	(1.4)
Allowance for Equity Funds Used During Construction	(3.0)	(2.4)
Mark-to-Market of Risk Management Contracts	(11.1)	(36.6)
Property Taxes	(49.3)	(44.0)
Deferred Fuel Over/Under-Recovery, Net	103.6	(53.6)
Change in Regulatory Assets	(43.8)	0.3
Change in Other Noncurrent Assets	5.0	45.1
Change in Other Noncurrent Liabilities	(22.4)	10.4
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(4.3)	(34.7)
Fuel, Materials and Supplies	(12.2)	8.7
Accounts Payable	81.2	46.2
Accrued Taxes, Net	39.7	41.3
Other Current Assets	20.5	(7.7)
Other Current Liabilities	(36.5)	(34.0)
Net Cash Flows from Operating Activities	384.7	217.5
INVESTING ACTIVITIES		
Construction Expenditures	(429.6)	(247.0)
Change in Advances to Affiliates, Net	(0.1)	153.8
Acquisition of the North Central Wind Energy Facilities	—	(658.0)
Other Investing Activities	0.8	3.2
Net Cash Flows Used for Investing Activities	(428.9)	(748.0)
FINANCING ACTIVITIES		
Capital Contribution from Parent	50.0	352.2
Issuance of Long-term Debt – Nonaffiliated	346.8	—
Change in Short-term Debt – Nonaffiliated	3.9	—
Change in Advances from Affiliates, Net	(278.1)	213.2
Retirement of Long-term Debt – Nonaffiliated	(94.1)	(3.1)
Principal Payments for Finance Lease Obligations	(16.2)	(5.4)
Dividends Paid on Common Stock	(50.0)	(12.5)
Dividends Paid on Common Stock – Nonaffiliated	(2.1)	(1.5)
Other Financing Activities	0.2	0.1
Net Cash Flows from (Used for) Financing Activities	(39.6)	543.0
Net Increase (Decrease) in Cash and Cash Equivalents	(83.8)	12.5
Cash and Cash Equivalents at Beginning of Period	88.4	51.2
Cash and Cash Equivalents at End of Period	$ 4.6	$ 63.7
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 48.7	$ 63.6
Net Cash Paid (Received) for Income Taxes	(17.1)	20.1
Noncash Acquisitions Under Finance Leases	2.6	2.8
Construction Expenditures Included in Current Liabilities as of June 30,	85.7	63.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 115.

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 six months ended June 30, 2023 is not necessarily indicative of results that may be expected for the year ending December 31, 2023. The condensed financial statements are unaudited and should be read in conjunction with the audited 2022 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 23, 2023.

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 June 30,			
	2023		2022	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 521.2		$ 524.5	
Weighted-Average Number of Basic AEP Common Shares Outstanding	514.9	$ 1.01	513.6	$ 1.02
Weighted-Average Dilutive Effect of Stock-Based Awards	1.3	—	1.6	—
Weighted-Average Number of Diluted AEP Common Shares Outstanding	516.2	$ 1.01	515.2	$ 1.02

	Six Months Ended June 30,			
	2023		2022	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 918.2		$ 1,239.2	
Weighted-Average Number of Basic AEP Common Shares Outstanding	514.5	$ 1.78	509.9	$ 2.43
Weighted-Average Dilutive Effect of Stock-Based Awards	1.4	—	1.5	(0.01)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	515.9	$ 1.78	511.4	$ 2.42

Equity Units are potentially dilutive securities and were excluded from the calculation of diluted EPS for the three and six months ended June 30, 2023 and 2022, as the dilutive stock price threshold was not met. See Note 12 - Financing Activities for more information related to Equity Units.

There were no antidilutive shares outstanding as of June 30, 2023 and 2022, 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:

	June 30, 2023		
	AEP	**AEP Texas**	**APCo**
		(in millions)	
Cash and Cash Equivalents	$ 304.9	$ 0.1	$ 6.8
Restricted Cash	45.8	30.7	15.1
Total Cash, Cash Equivalents and Restricted Cash	$ 350.7	$ 30.8	$ 21.9

	December 31, 2022		
	AEP	**AEP Texas**	**APCo**
		(in millions)	
Cash and Cash Equivalents	$ 509.4	$ 0.1	$ 7.5
Restricted Cash	47.1	32.7	14.4
Total Cash, Cash Equivalents and Restricted Cash	$ 556.5	$ 32.8	$ 21.9

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 AEP only. The impact of AOCI is not material to the financial statements of the Registrant Subsidiaries.

Presentation of Comprehensive Income

The following tables provide AEP's 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.

Three Months Ended June 30, 2023	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of March 31, 2023	$ 65.3	$ 6.1	$ (139.5)	$ (68.1)
Change in Fair Value Recognized in AOCI, Net of Tax	5.9	7.0	—	12.9
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	28.3	—	—	28.3
Interest Expense (a)	—	(0.5)	—	(0.5)
Amortization of Prior Service Cost (Credit)	—	—	(5.3)	(5.3)
Amortization of Actuarial (Gains) Losses	—	—	1.4	1.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	28.3	(0.5)	(3.9)	23.9
Income Tax (Expense) Benefit	6.0	(0.1)	(0.8)	5.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	22.3	(0.4)	(3.1)	18.8
Net Current Period Other Comprehensive Income (Loss)	28.2	6.6	(3.1)	31.7
Balance in AOCI as of June 30, 2023	$ 93.5	$ 12.7	$ (142.6)	$ (36.4)

Three Months Ended June 30, 2022	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of March 31, 2022	$ 404.0	$ (13.6)	$ 40.2	$ 430.6
Change in Fair Value Recognized in AOCI, Net of Tax	257.3	2.0	—	259.3
Amount of (Gain) Loss Reclassified from AOCI				
Generation & Marketing Revenues (a)	0.1	—	—	0.1
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(161.8)	—	—	(161.8)
Interest Expense (a)	—	1.1	—	1.1
Amortization of Prior Service Cost (Credit)	—	—	(5.4)	(5.4)
Amortization of Actuarial (Gains) Losses	—	—	2.1	2.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(161.7)	1.1	(3.3)	(163.9)
Income Tax (Expense) Benefit	(34.0)	0.3	(0.7)	(34.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(127.7)	0.8	(2.6)	(129.5)
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)	129.6	2.8	(11.6)	120.8
Balance in AOCI as of June 30, 2022	$ 533.6	$ (10.8)	$ 28.6	$ 551.4

Six Months Ended June 30, 2023	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of December 31, 2022	$ 223.5	$ 0.3	$ (140.1)	$ 83.7
Change in Fair Value Recognized in AOCI, Net of Tax	(189.4)	12.2	(12.9)	(190.1)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	75.3	—	—	75.3
Interest Expense (a)	—	0.2	—	0.2
Amortization of Prior Service Cost (Credit)	—	—	(10.6)	(10.6)
Amortization of Actuarial (Gains) Losses	—	—	2.6	2.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	75.3	0.2	(8.0)	67.5
Income Tax (Expense) Benefit	15.9	—	(1.7)	14.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	59.4	0.2	(6.3)	53.3
Reclassifications of KPCo Pension and OPEB Regulatory Assets from AOCI	—	—	21.1	21.1
Income Tax (Expense) Benefit	—	—	4.4	4.4
Reclassifications of KPCo Pension and OPEB Regulatory Assets from AOCI, Net of Income Tax (Expense) Benefit	—	—	16.7	16.7
Net Current Period Other Comprehensive Income (Loss)	(130.0)	12.4	(2.5)	(120.1)
Balance in AOCI as of June 30, 2023	$ 93.5	$ 12.7	$ (142.6)	$ (36.4)

Six Months Ended June 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, Net of Tax	535.5	8.8	—	544.3
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(209.7)	—	—	(209.7)
Interest Expense (a)	—	2.2	—	2.2
Amortization of Prior Service Cost (Credit)	—	—	(10.3)	(10.3)
Amortization of Actuarial (Gains) Losses	—	—	4.2	4.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(209.7)	2.2	(6.1)	(213.6)
Income Tax (Expense) Benefit	(44.1)	0.5	(1.3)	(44.9)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(165.6)	1.7	(4.8)	(168.7)
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)	369.9	10.5	(13.8)	366.6
Balance in AOCI as of June 30, 2022	$ 533.6	$ (10.8)	$ 28.6	$ 551.4

(a) 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 2022 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2022 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 2023 and updates the 2022 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 is not deemed recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulated Generating Units that have been Retired

SWEPCo

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 through 2046, 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 through 2027, 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.As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo's Louisiana share of the Dolet Hills Power Station, through a separate rider, through 2032, but did not rule on the prudency of the early retirement of the plant, which is being addressed in a separate proceeding. See "2020 Texas Base Rate Case" and "2020 Louisiana Base Rate Case" sections below for additional information.

In March 2023, the Pirkey Plant was retired.As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo's Louisiana jurisdictional share of the Pirkey Plant, through a separate rider, through 2032. As part of the 2021 Arkansas Base Rate Case, the APSC granted SWEPCo regulatory asset treatment.SWEPCo will request recovery including a weighted average cost of capital carrying charge through a future proceeding. The Texas jurisdictional share of the Pirkey Plant will be addressed in SWEPCo's next base rate case.

Regulated Generating Units to be Retired

PSO

In 2014, PSO received final approval from the Federal EPA to close Northeastern Plant, Unit 3, in 2026The 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 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 June 30, 2023, 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	$ 120.5	$ 154.9	$ 20.4	(b)	2026		(c)	$ 14.9
Welsh Plant, Units 1 and 3	384.3	105.4	58.2	(d)	2028	(e)	(f)	38.6

(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 the removal of Northeastern Plant, Unit 3, after retirement.
(c) Northeastern Plant, Unit 3 is currently being recovered through 2040.
(d) Includes Welsh Plant, Unit 2, which was retired in 2016. Removal of Welsh Plant, Unit 2, will be performed with the removal of Welsh Plant, Units 1 and 3, after retirement.
(e) Represents projected retirement date of coal assets, units are being evaluated for conversion to natural gas after 2028.
(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 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 rate riders. As of June 30, 2023, SWEPCo's share of the net investment in the Dolet Hills Power Station was $108 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 June 30, 2023, SWEPCo had a net under-recovered fuel balance of $120 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 $34 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 $34 million deferral, with refunds to customers over five years. In September 2022, SWEPCo filed rebuttal testimony addressing the LPSC staff recommendations and a hearing was held in May 2023.

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 June 2023, an unopposed settlement agreement was filed with the PUCT that would provide recovery of $48 million of Oxbow mine related costs through 2035. A decision from the PUCT on the unopposed settlement agreement is expected in the fourth quarter of 2023.

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 March 2023, the Pirkey Plant was retired.SWEPCo is recovering, or will seek recovery of, the remaining net book value of Pirkey Plant non-fuel costs. As of June 30, 2023, SWEPCo's share of the net investment in the Pirkey Plant was $177 million, including materials and supplies, net of cost of removal. See the "Regulated Generating Units that have been Retired" section above for additional information.Fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions. As of March 31, 2023, SWEPCo fuel deliveries, including billings of all fixed costs, from Sabine ceased. Additionally, as of June 30, 2023, SWEPCo had a net under-recovered fuel balance of $120 million, inclusive of costs related to the Pirkey Plant billed by Sabine, but excluding impacts of the February 2021 severe winter weather event.Remaining operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in existing fuel clauses.

In June 2023, an unopposed settlement agreement was filed with the PUCT that would provide recovery of $33 million of Sabine related fuel costs through 2035. In July 2023, Texas ALJs issued a proposal for decision that concluded the decision to retire the Pirkey Plant was prudent.A decision from the PUCT on the unopposed settlement agreement and the Texas ALJ proposal for decision is expected in the second half of 2023.

Additionally in July 2023, the LPSC ordered that a separate proceeding be established to review the prudence of the decision to retire the Pirkey Plant, including the costs included in fuel for years starting in 2019 and after.

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

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

	AEP	
	June 30, 2023	December 31, 2022
Noncurrent Regulatory Assets	(in millions)	
Regulatory Assets Currently Earning a Return		
Pirkey Plant Accelerated Depreciation	$ 111.8	$ 116.5
Unrecovered Winter Storm Fuel Costs (a)	109.5	121.7
Welsh Plant, Units 1 and 3 Accelerated Depreciation	105.4	85.6
Dolet Hills Power Station Fuel Costs - Louisiana	33.9	32.0
Texas Mobile Generation Costs	29.4	17.6
Other Regulatory Assets Pending Final Regulatory Approval	21.4	19.3
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (b)(c)(d)	395.4	407.2
2020-2022 Virginia Triennial Under-Earnings	35.0	37.9
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	25.9
Other Regulatory Assets Pending Final Regulatory Approval	49.3	55.6
Total Regulatory Assets Pending Final Regulatory Approval	$ 917.0	$ 919.3

(a) Includes $37 million and $37 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of June 30, 2023 and December 31, 2022, respectively. See the "February 2021 Severe Winter Weather Impacts in SPP" section below for additional information.

(b) In April 2023, OPCo filed a request with the PUCO for recovery of $34 million in Ohio storm-related costs.

(c) In April 2023, the LPSC issued an order approving the prudence and future recovery of the Louisiana storm-related regulatory assets. See "2021 Louisiana Storm Cost Filing" section below for additional information.

(d) In June 2023, storms in the Oklahoma, Louisiana and Texas service territories caused power outages and extensive damage resulting in the deferral of $52 million, $28 million and $20 million, respectively. Recovery of these storm costs will be addressed in a future request.

Noncurrent Regulatory Assets	AEP Texas	
	June 30, 2023	December 31, 2022
	(in millions)	
Regulatory Assets Currently Earning a Return		
Texas Mobile Generation Costs	$ 29.4	$ 17.6
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	34.9	26.7
Vegetation Management Program	5.2	5.2
Texas Retail Electric Provider Bad Debt Expense	4.1	4.1
Other Regulatory Assets Pending Final Regulatory Approval	13.6	13.4
Total Regulatory Assets Pending Final Regulatory Approval	$ 87.2	$ 67.0

Noncurrent Regulatory Assets	APCo	
	June 30, 2023	December 31, 2022
	(in millions)	
Regulatory Assets Currently Earning a Return		
COVID-19 – Virginia	$ 7.2	$ 7.0
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs - West Virginia	72.0	72.6
2020-2022 Virginia Triennial Under-Earnings	35.0	37.9
Plant Retirement Costs – Asset Retirement Obligation Costs	25.9	25.9
Other Regulatory Assets Pending Final Regulatory Approval	5.5	1.1
Total Regulatory Assets Pending Final Regulatory Approval	$ 145.6	$ 144.5

Noncurrent Regulatory Assets	I&M	
	June 30, 2023	December 31, 2022
	(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		
Storm-Related Costs - Indiana	23.9	21.6
Other Regulatory Assets Pending Final Regulatory Approval	2.7	2.0
Total Regulatory Assets Pending Final Regulatory Approval	$ 26.7	$ 23.7

Noncurrent Regulatory Assets	OPCo June 30, 2023	OPCo December 31, 2022
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (a)	$ 52.7	$ 33.8
Other Regulatory Assets Pending Final Regulatory Approval	0.1	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 52.8	$ 33.8

(a) In April 2023, OPCo filed a request with the PUCO for recovery of $34 million in storm costs.

Noncurrent Regulatory Assets	PSO June 30, 2023	PSO December 31, 2022
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (a)	$ 84.6	$ 25.5
Other Regulatory Assets Pending Final Regulatory Approval	0.2	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$ 84.8	$ 25.6

(a) In June 2023, storms caused power outages and extensive damage to the Oklahoma service territory, resulting in the deferral of $52 million. Recovery for these storm costs will be included in a future request.

Noncurrent Regulatory Assets	SWEPCo June 30, 2023	SWEPCo December 31, 2022
	(in millions)	
Regulatory Assets Currently Earning a Return		
Pirkey Plant Accelerated Depreciation	$ 111.8	$ 116.5
Unrecovered Winter Storm Fuel Costs (a)	109.5	121.7
Welsh Plant, Units 1 and 3 Accelerated Depreciation	105.4	85.6
Dolet Hills Power Station Fuel Costs - Louisiana	33.9	32.0
Dolet Hills Power Station	12.1	9.7
Other Regulatory Assets Pending Final Regulatory Approval	1.9	2.5
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (b)(c)	48.0	151.5
Asset Retirement Obligation - Louisiana	—	11.8
Other Regulatory Assets Pending Final Regulatory Approval	15.9	16.0
Total Regulatory Assets Pending Final Regulatory Approval	$ 438.5	$ 547.3

(a) Includes $37 million and $37 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of June 30, 2023 and December 31, 2022, respectively. See the “February 2021 Severe Winter Weather Impacts in SPP” section below for additional information.

(b) In April 2023, the LPSC issued an order approving the prudence and future recovery of the Louisiana storm-related regulatory assets. See “2021 Louisiana Storm Cost Filing” section below for additional information.

(c) In June 2023, additional storms in the Louisiana and Texas service territories caused power outages and extensive damage resulting in the deferral of $28 million and $20 million, respectively. Recovery of these storm costs will be addressed in a future request.

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 June 30, 2023, AEP Texas' cumulative revenues from interim base rate increases that are subject to review is approximately $791 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)

2020-2022 Virginia Triennial Review

In March 2023, APCo submitted its 2020-2022 Virginia triennial review filing and base rate case with the Virginia SCC as required by state law. APCo requested a $213 million annual increase in Virginia base rates based upon a proposed 10.6% return on common equity. The requested annual increase includes $47 million related to vegetation management and a $35 million increase in depreciation expense. The requested increase in depreciation expense reflects, among other things, the impacts of incremental investments made since APCo's last depreciation study using property balances as of December 31, 2022. Effective January 1, 2023 and in accordance with past Virginia SCC directives, APCo implemented updated Virginia depreciation rates. APCo's proposed revenue requirement also includes the recovery of certain costs incurred that partially contributed to APCo's calculated earnings shortfall for the 2020-2022 triennial 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 certain categories of costs, including major storm costs for severe weather events. As of June 30, 2023, APCo deferred approximately $35 million related to previously incurred major storm costs as a result of APCo's calculation of Virginia earnings below the bottom of its authorized ROE band during the 2020-2022 Triennial Review period.

In July 2023, intervening parties submitted testimony recommending a $69 million annual Virginia base rate increase based on the following significant adjustments: (a) a 9.2% ROE, (b) a $36 million decrease in depreciation expense using a 2040 estimated Amos Plant retirement date for Virginia ratemaking purposes rather than the 2032/2033 retirement date requested by APCo, (c) the removal of $40 million of APCo's requested increase in vegetation management expense, (d) the removal of $23 million in major storm expenses incurred during the 2020-2022 triennial period, and (e) the removal of $15 million of forecasted spending related to boiler maintenance and generation consumables expense. Virginia staff testimony is due in the third quarter of 2023 and a Virginia SCC order will be issued in the fourth quarter of 2023.

Any APCo Virginia jurisdictional costs that are not recoverable or any refunds of revenues collected from customers during the triennial review period that are ordered by the Virginia SCC for the 2020-2022 Triennial Review period could reduce future net income and cash flows and impact financial condition.

ENEC (Expanded Net Energy Cost) Filings

In April 2021, APCo and WPCo (the Companies) requested a combined $3 million annual increase in ENEC rates based on a cumulative $55 million ENEC under-recovery as of February 28, 2021 and an $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 costsHowever, the WVPSC stated that actual and projected ENEC costs are still 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 reviewIn February 2023, the WVPSC issued an order stating that the commission will not grant additional rate increases for fuel costs until the WVPSC staff completes its prudency review.

In April 2023, the Companies submitted their 2023 annual ENEC filing with the WVPSC, proposing two alternatives to increase ENEC rates effectiv September 1, 2023. The first alternative is a $293 million annual increase in ENEC rates comprised of an $89 million increase for current year ENEC expense and a $200 million annual increase for the recovery of the Companies' February 28, 2023 ENEC under-recovery balances over three years, including debt and equity carrying costs. The second alternative is an $89 million annual increase in ENEC rates with the Companies securitizing approximately $1.9 billion of assets, including: (a) $553 million relating to ENEC under-recoveries as of February 28, 2023, (b) $8 million relating to major storm expense deferrals and (c) $1.2 billion relating to APCo's West Virginia jurisdictional book values of the Amos and Mountaineer Plants and forecasted CCR and ELG investments at these generating facilities.The Companies continue to reflect ENEC under-recovery balances as current on their balance sheets since management cannot assert whether the WVPSC will approve recovery of ENEC under-recovery balances over a time frame different from the traditional one-year period.

Additionally, in April 2023, the Staff submitted the prudency review prepared by an independent consultant retained by the WVPSC staff of the Companies' operation of the Amos, Mountaineer and Mitchell coal plants that Staff was directed to conduct by the WVPSC in May 2022 (Consultant's Report). The Consultant's Report states the opinion of the consultant that the Companies acted imprudently by not taking steps to achieve a 69% capacity factor at their coal-fired plants and recommends applying a disallowance factor of 52.9% to the Companies' cumulative, September 30, 2022 ENEC under-recovery balance of approximately $430 million. The Consultant's Report further states the consultant's opinion that this disallowance factor could also be utilized in future ENEC filings.Adoption of the Consultant's Report's findings by the WVPSC could result in a disallowance of up to $285 million. The Companies disagree with the conclusions and recommendations contained in the Consultant's Report and intend to dispute them in the appropriate proceedings before the WVPSC.In May 2023, the WVPSC established a procedural schedule for the 2021, 2022 and 2023 ENEC cases to begin in the third quarter of 2023, including APCo's response to the independent consultant's prudency review.

If any deferred ENEC 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 June 30, 2023, AEP's share of ETT's cumulative revenues that are subject to review is approximately $1.6 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, 2025, during which the $1.6 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)

In April 2023, I&M received intervenor testimony in I&M's 2021 PSCR Reconciliation for the 12-month period ending December 31, 2021 recommending disallowances of purchased power costs of $18 million associated with the OVEC Inter-Company Power Agreement (ICPA) and the AEGCo Unit Power Agreement (UPA) that were alleged to be above market in applying the MPSC's Code of Conduct rules. Michigan staff submitted testimony in I&M's 2021 PSCR Reconciliation with no recommended disallowances for PSCR costs incurred, including those associated with the OVEC ICPA and the AEGCo UPA. Michigan staff also recommended several options to address I&M's shortfall in achieving Michigan's annual one percent energy waste reduction savings level, resulting in potential future disallowed costs of up to approximately $14 million. In June 2023, Michigan staff submitted rebuttal testimony to update their calculation of the 2021 market proxy price resulting in a recommended disallowance of approximately $1 million related to the OVEC ICPA. An MPSC order on I&M's 2021 PSCR Reconciliation is expected in the fourth quarter of 2023. If any PSCR costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

Fuel Adjustment Clause (FAC) Purchased Power Limitation

In May 2023, KPCo filed an application seeking authority to defer, for future recovery, approximately $12 million of December 2022 purchased power costs not recoverable through its FAC. This requested deferral accounting authority would have enabled KPCo to pursue securitization of these costs. In June 2023, the KPSC denied KPCo's request for deferral accounting authority.

Also in June 2023, following its order denying KPCo's request for deferral accounting authority, the KPSC issued an order directing KPCo to show cause why it should not be subject to Kentucky statutory remedies, including fines and penalties, for failure to provide adequate service in its service territory. The KPSC's show cause order did not make any determination regarding the adequacy of KPCo's service. In July 2023, KPCo filed a response to the show cause order demonstrating that it has provided adequate service.

KPCo is requesting a prudency determination and recovery mechanism for these costs in its 2023 base rate. Unless and until KPCo is granted a recovery mechanism for these purchased power costs from the KPSC it will impact cash flows and financial condition. Additionally, if any fines or penalties are levied against KPCo relating to the show cause order, it will reduce net income and cash flows and impact financial condition.

2023 Kentucky Base Rate and Securitization Case

In June 2023, KPCo filed a request with the KPSC for a $94 million net annual increase in base rates based upon a proposed 9.9% ROE with the increase to be implemented no earlier than January 2024. The filing proposes no changes in depreciation rates and an annual level of storm restoration expense in base rates of approximately $1 million. KPCo also proposed to discontinue tracking of PJM transmission costs through a rider, and to instead collect an annual level of costs through base rates. In addition, KPCo has proposed a rider to recover certain distribution reliability investments and related incremental operation and maintenance expenses. KPCo also requested a prudency determination and recovery mechanism for approximately $16 million of purchased power costs not recoverable through its FAC since its last base case.

In conjunction with its June 2023 filing, KPCo further requested to finance, through the issuance of securitization bonds, approximately $471 million of regulatory assets recorded as of June 2023 including: (a) $289 million of plant retirement costs, (b) $79 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, (c) $52 million of deferred purchased power expenses and (d) $51 million of under-recovered purchased power rider costs. Plant retirement costs and deferred purchased power expenses have been deemed prudent in prior KPSC decisions.KPCo has requested a prudency determination for the deferred storm costs and under-recovered purchase power rider costs since the last base case in this proceeding. Consistent with Kentucky statutory requirements, the present value of the return on accumulated deferred income tax benefits related to plant retirement costs and deferred purchase power expenses were proposed to reduce the amount authorized to be financed through securitization.

Intervenor testimony is due in the third quarter of 2023 and an order from the KPSC is expected in January 2024.If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

OPCo Rate Matters (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 OPCo 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 of these disputes, however, if any costs are disallowed or refunds are ordered it could reduce future net income and cash flows and impact financial condition. See "OVEC" section of Note 17 in the 2022 Annual Report for additional information on AEP and OPCo’s investment in OVEC.

Ohio ESP Filings

In January 2023, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments, proposed new riders and the continuation and modification of certain existing riders, including the Distribution Investment Rider, effective June 2024 through May 2030. The proposal includes a return on common equity of 10.65% on capital costs for certain riders. In June 2023, intervenors filed testimony opposing OPCo’s plan for various new riders and modifications to existing riders, including the DIR. Staff testimony and a hearing is expected in the third quarter of 2023. If OPCo is ultimately not permitted to fully collect its ESP rates it could reduce future net income and cash flows and impact financial condition.

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

2022 Oklahoma Base Rate Case

In November 2022, PSO filed a request with the OCC for a $173 million annual increase in rates based upon a 10.4% ROE with a capital structure of 45.4% debt and 54.6% common equity, net of existing rider revenues and certain incremental renewable facility benefits expected to be provided to customers through riders. The requested annual revenue increase includes a $47 million annual depreciation expense increase related to the accelerated depreciation recovery of the Northeastern Plant, Unit 3 through 2026, and a $16 million annual amortization expense increase to recover intangible plant over a 5-year useful life instead of a 10-year useful life. PSO's request also includes recovery of the 154 MW Rock Falls Wind Facility through base rates to aid PSO's near-term capacity needs and support compliance with SPP's 2023 increased capacity planning reserve margin requirements. In November 2022, PSO entered into an agreement to acquire the Rock Falls Wind Facility. In February 2023, the FERC approved PSO's acquisition of the Rock Falls Wind Facility under Section 203 of the Federal Power Act. PSO closed on the acquisition and placed the Rock Falls Wind Facility in-service on March 31, 2023. In addition, PSO requested an annual formula based rate tariff, with an initial one-year pilot term. In the event the requested formula based rate tariff is denied, PSO has requested an expanded rider to recover certain distribution investments and related expenses as well as an expanded transmission cost recovery rider.

In March 2023, OCC staff and various intervenors filed testimony supporting net annual revenue changes ranging from a $42 million net decrease to a $49 million net increase based upon ROEs ranging from 8.6% to 9.5%. The difference between PSO's request and OCC staff and intervenor testimony is primarily due to: (a) rejection of PSO's request to accelerate the recovery of Northeastern Plant, Unit 3 from its original retirement date of 2040 to its projected retirement date of 2026, (b) rejection of PSO's request to recover intangible plant over a 5-year useful life instead of a 10-year useful life, (c) recommended disallowance of approximately $9 million in certain distribution plant investments, (d) opposition to inclusion of the Rock Falls Wind Facility revenue requirement in customer rates before PSO's next base rate case, (e) opposition to PSO's inclusion of its deferred tax asset associated with net operating loss on a stand-alone tax basis in rate base and (f) lower recommended ROEs and recommendations to use certain hypothetical capital structures. Parties also recommended that the OCC reject PSO's requested formula based rate, and alternate requests for expanded distribution investment and transmission cost recovery riders.

In May 2023, PSO, OCC staff and certain intervenors filed a contested joint stipulation and settlement agreement with the OCC that includes an annual revenue increase of $50 million, based upon a 9.5% ROE with a capital structure of 45.4% debt and 54.6% common equity, net of existing rider revenues and certain incremental renewable facility benefits expected to be provided to customers through riders. The net annual increase includes recovery of the 154 MW Rock Falls Wind Facility through base rates. Northeastern Plant, Unit 3 will continue to be recovered through 2040 and intangible plant will continue to be recovered over a 10-year useful life. The agreement also provides for certain rider-related items, including: (a) revision to PSO's Fuel Clause Adjustment Rider to reflect factor updates to occur on a semi-annual basis, (b) approval to defer a weighted average cost of capital carrying charge on PSO's deferred tax asset associated with net operating loss on a stand-alone tax basis to a regulatory asset and, contingent upon receipt of a supportive private letter ruling from the IRS, approval to collect the deferral through a rider over a 20-month period, and (c) approval to implement an expanded rider to recover certain distribution investments for a three-year term, up to a $6 million annual revenue requirement.

In May 2023, a hearing on the merits of the contested joint stipulation and settlement agreement was held at the OCC and PSO implemented an interim annual base rate increase, subject to refund, based upon the contested joint stipulation and settlement agreement. Through June 30, 2023, PSO's cumulative revenue from the interim annual base rate increase, subject to refund, is approximately $16 million. In July 2023, an ALJ report was filed and included recommendations generally consistent with the intervenor testimony. The ALJ report is not binding on the OCC. A final order is expected in the third quarter of 2023. If PSO is required to refund any of the $16 million of revenue recorded subject to refund or any costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.

<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 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 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. In December 2022, SWEPCo and the PUCT filed requests for rehearing with the Texas Supreme Court. In June 2023, the Texas Supreme Court denied SWEPCo's request for rehearing and the case was 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 June 30, 2023. 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 SWEPCo is ultimately unable to recover AFUDC in excess of the Texas jurisdictional cost cap, SWEPCo estimates it may be required to make customer refunds ranging from $0 to $195 million related to revenues collected from February 2013 through June 2023 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 related to limiting SWEPCo's recovery of AFUDC on Turk Plant and recovery of Welsh Plant, Unit 2. 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 to 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 to 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's requested annual increase includes accelerated depreciation related to the Dolet Hills Power Station, Pirkey Power Plant and Welsh Plant, all of which were or are expected to be retired early. SWEPCo also included recovery of Welsh Plant, Unit 2 over the blended useful life of Welsh Plant, Units 1 and 3. SWEPCo subsequently revised the requested annual increase to $95 million to reflect removing hurricane storm restoration costs from the base case filing, to modify the proposed recovery of the Dolet Hills Power Station and revisions to various proposed amortizations. The hurricane costs have been requested in a separate storm filing. See "2021 Louisiana Storm Cost Filing" below for more information.

In January 2023, the LPSC approved a settlement which provides for an annual revenue increase of $27 million based upon a 9.5% ROE and includes: (a) a $21 million increase in base rates effective February 2023, (b) a $14 million rider to recover costs of the Dolet Hills Power Station and Pirkey Plant including a return, (c) an $8 million reduction in fuel rates, (d) an adoption of a 3-year formula rate term subject to an earnings band and (e) the recovery of certain incremental SPP charges net of associated revenue and the Louisiana jurisdictional share of the return on and of projected transmission capital investment outside of the earnings band. The settlement agreement did not rule on the prudency of the early retirement of the Dolet Hills Power Station, which is being addressed in a separate proceeding.

The primary differences between SWEPCo's requested annual rate increase and the agreed upon settlement increase are primarily due to: (a) a reduction in the requested ROE, (b) recovery of the Dolet Hills Power Station and Pirkey Plant over ten years in a separate rider mechanism as opposed to base rates with accelerated depreciation rates, (c) maintaining existing depreciation rates for Welsh Plant, Units 1 and 3 and (d) the severing of SWEPCo's proposed adjustment to include a stand-alone NOLC deferred tax asset in rate baseIn January 2023, a hearing was held related to the inclusion of a stand-alone NOLC deferred tax asset in rate base and an order from the LPSC is expected in 2023.

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 March 2023, SWEPCo and the LPSC staff filed a joint stipulation and settlement agreement with the LPSC which confirmed the prudency of $150 million of deferred incremental storm restoration expenses. The agreement also authorized an interim carrying charge at a rate of 3.125% until the recovery mechanism is determined in phase two of this proceeding. SWEPCo will submit additional information in phase two of this proceeding to determine whether securitization of the costs is more cost effective than recovery through typical ratemaking. In April 2023, the LPSC issued an order approving the stipulation and settlement agreement.

February 2021 Severe Winter Weather Impacts in SPP

In February 2021, 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 shown in the table below:

Jurisdiction	June 30, 2023	December 31, 2022	Approved Recovery Period	Approved Carrying Charge
	(in millions)			
Arkansas	$ 66.4	$ 74.9	6 years	(a)
Louisiana	109.5	121.7	(b)	(b)
Texas	117.8	132.4	5 years	1.65%
Total	$ 293.7	$ 329.0		

(a) SWEPCo is permitted to record carrying costs on the unrecovered balance of fuel costs at a weighted-cost of capital approved by the APSC.
(b) 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 equal to the prime rate. The special order states the fuel and purchased power costs incurred will be subject to a future LPSC audit.

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 2019 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 had an immaterial impact to the financial statements of AEP, AEPTCo, PSO and SWEPCo. In November 2022, certain joint customers appealed the FERC decision to the U.S. Court of Appeals for the District of Columbia Circuit.

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 the second half of 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 June 30, 2023, AEP's share of IEC capital expenditures was approximately $90 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 OCC 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 OCC'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.In December 2022, the FERC issued an order removing the50 basis point RTO incentive from OPCo and OHTCo transmission formula rates effective the date of the February 2022 complaint filing and directed OPCo and OHTCo to provide refunds, with interest, within sixty days of the date of its order.In January 2023, both AEPSC and the OCC filed requests for rehearing with the FERC.In February 2023, in compliance with the FERC's December 2022 order, AEPSC submitted a filing to the FERC to update OPCo and OHTCo 2023 transmission formula rates to exclude the50 basis point RTO incentive and provide refunds with interest. In April 2023, the FERC approved the updated transmission formula rates for OPCo and OHTCo and issued an Order on Rehearing affirming its February 2022 decision. This decision has been appealed to the U.S. Court of Appeals for the Sixth Circuit. Management expects the December 2022 FERC order to reduce AEP's pretax income by approximately $20 million on an annual basis.

Request to Update AEGCo Depreciation Rates (Applies to AEP and I&M)

In October 2022, AEP, on behalf of AEGCo, submitted proposed revisions to AEGCo's depreciation rates for its 50% ownership interest in Rockport Plant, Unit 1 and Unit 2, reflected in AEGCo's unit power agreement with I&M. The proposed depreciation rates for these assets reflect an estimated 2028 retirement date for the Rockport Plant. AEGCo's previous FERC-approved depreciation rates for Rockport Plant, Unit 1 were based upon a December 31, 2028 estimated retirement date while AEGCo's previous FERC-approved depreciation rates for Rockport Plant, Unit 2 leasehold improvements were based upon a December 31, 2022 estimated retirement date in conjunction with the termination of the Rockport Plant, Unit 2 lease.

In December 2022, the FERC issued an order approving the proposed AEGCo Rockport depreciation rates effective January 1, 2023, subject to further review and a potential refund. The FERC established a separate proceeding to review: (a) AEGCo's acquisition value for the Rockport Plant, Unit 2 base generating asset (original cost and accumulated depreciation), (b) the appropriateness of including future capital additions as stated components in proposed depreciation rates, in light of the Unit Power Agreement's formula rate mechanism, (c) the appropriateness of applying two different depreciation rates to a single asset common to both units and (d) the accounting and regulatory treatment of Rockport Plant, Unit 2 costs of removal and related AROs. It is expected that the FERC will issue an order on this review in the second half of 2023.This FERC review and subsequent order on these issues could reduce future net income and cash flows and impact financial condition.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge (Applies to AEP, AEPTCo, APCo, I&M, PSO and SWEPCo)

In March 2023 and May 2023, certain joint customers submitted a complaint and a formal challenge at the FERC related to the 2022 Annual Update of the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP, respectively.These challenges primarily relate to stand-alone treatment of NOLCs in the transmission formula rates of the AEP transmission owning subsidiaries.AEPSC, on behalf of the AEP transmission owning subsidiaries within PJM and SPP, filed answers to the joint formal challenge and complaint with the FERC in the second quarter of 2023.

The Registrants transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 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 annual revenue requirements for years 2023, 2022, and 2021 by $60 million, $69 million and $78 million, respectively. Through the second quarter of 2023, the Registrants' financial statements reflect a provision for refund for certain NOLC revenues billed by PJM and SPPAlso, a certain portion of the impact including NOLCs 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". If the Registrants are required to make refunds as a result of these challenges, it could reduce future net income and cash flows and impact financial condition.

5. <u>COMMITMENTS, GUARANTEES AND CONTINGENCIES</u>

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 2022 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 2025, respectively, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of June 30, 2023, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of June 30, 2023 were as follows:

Company	Amount		Maturity
	(in millions)		
AEP	$	288.8	July 2023 to June 2024
AEP Texas		1.8	July 2023

Guarantees of Equity Method Investees (Applies to AEP)

Parent has issued guarantees over the performance of certain non-consolidated joint ventures included within the competitive contracted renewables portfolio and NM Renewable Development, LLC.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 June 30, 2023, the maximum potential amount of future payments associated with the remaining guarantees was $78 million, with the last guarantee expiring in December 2045. The non-contingent liability recorded associated with these guarantees was $5 million, with an additional $1 million 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 June 30, 2023, 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 June 30, 2023, 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	$ 45.0
AEP Texas	10.9
APCo	5.6
I&M	4.2
OPCo	7.0
PSO	4.7
SWEPCo	5.4

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

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 U. S. District Court for the Southern District of Ohio against AEP and certain of its officers for alleged violations of securities laws. 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 U.S. 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 substantive and forum-based motions to dismiss on April 29, 2022. On September 13, 2022, the New York state court granted the forum-based motion to dismiss with prejudice and the plaintiff subsequently filed a notice of appeal with the New York appellate court. On January 20, 2023, the New York plaintiff filed a motion to intervene in the pending Ohio federal court action and withdrew his appeal in New York. 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 the amended complaint and subsequently filed a brief in opposition to the New York plaintiffs' motion to intervene in the consolidated action in Ohio. On March 20, 2023, the federal district court issued an order granting the motion to dismiss with prejudice and denying the New York plaintiffs' motion to intervene. On April 20, 2023, one of the plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Sixth Circuit of the Ohio federal district court order dismissing the consolidated action and denying the intervention.On June 15, 2022, the Ohio state court entered an order continuing the stays of that case until the final 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 was directed to the Board of Directors of AEP (AEP Board) and contained factual allegations involving HB 6 that were generally consistent with those in the derivative litigation filed in state and federal court. The shareholder that sent the letter has since withdrawn the litigation demand, which is now terminated and of no further effect. In April 2023, AEP received a litigation demand from counsel representing the purported AEP shareholder who filed the dismissed derivative action in New York state court and unsuccessfully tried to intervene in the consolidated derivative actions in Ohio federal court. The litigation demand letter is directed to the AEP Board 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 certain current and former directors and officers, and that AEP commence a civil action for breaches of fiduciary duty and related claims against any individuals who allegedly harmed AEP. The AEP Board will act in response to the letter as appropriate. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

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 investigation.AEP is cooperating fully with the SEC's investigation, which has included taking testimony from certain individuals and inquiries regarding Empowering Ohio's Economy, Inc., which is a 501(c)(4) social welfare organization, and related disclosures. Although the outcome of the SEC's investigation cannot be predicted, management does not believe the results of this investigation will have a material impact on financial condition, results of operations or cash flows.

Claims for Indemnification Made by Owners of the Gavin Power Station

In November 2022, the Federal EPA issued a final decision denying Gavin Power LLC's requested extension to allow a CCR surface impoundment at the Gavin Power Station to continue to receive CCR and non-CCR waste streams after April 11, 2021 until May 4, 2023 (the Gavin Denial).As part of the Gavin Denial, the Federal EPA made several determinations related to the CCR Rule (see "Environmental Issues - Coal Combustion Residual (CCR) Rule" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information), including a determination that the closure of the 300 acre unlined fly ash reservoir (FAR) is noncompliant with the CCR Rule in multiple respects.The Gavin Power Station was formerly owned and operated by AEP and was sold to Gavin Power LLC and Lightstone Generation LLC in 2017. Pursuant to the PSA, AEP maintained responsibility to complete closure of the FAR in accordance with the closure plan approved by the Ohio EPA which was completed in July 2021. The PSA contains indemnification provisions, pursuant to which the owners of the Gavin Power Station have notified AEP they believe they are entitled to indemnification for any damages that may result from these claims, including any future enforcement or litigation resulting from the Federal EPA's determinations of noncompliance with various aspects of the CCR Rule as part of the Gavin Denial.The owners of the Gavin Power Station have also sought indemnification for landowner claims for property damage allegedly caused by modifications to the FAR. Management does not believe that the owners of the Gavin Power Station have any valid claim for indemnity or otherwise against AEP under the PSA. In addition, Gavin Power

LLC, several AEP subsidiaries, and other parties have filed Petitions for Review of the Gavin Denial with the U.S. Court of Appeals for the Distric of Columbia Circuit. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Claims for Damages Related to Sabine Lignite Mining Agreement

In May 2023, North American Coal Corporation (NACC) and Sabine, a subsidiary of NACC, filed suit against SWEPCo in Texas state court fo breach of the Lignite Mining Agreement (LMA) between Sabine and SWEPCo. NACC and Sabine assert that the terms of the LMA require SWEPCo to continue operating the Pirkey Plant and obtaining coal from the Sabine mine through 2035 and that SWEPCo has breached the agreement by closing the plant. The complaint seeks both injunctive relief ordering SWEPCo to cease demolition and reclamation activities at the Pirkey Plant and the Sabine mine and damages, which Sabine has asserted are $85 million in lost fees. The parties have entered into a standstill agreement staying both the litigation and certain demolition and reclamation activities at the Pirkey Plant and the Sabine mine. SWEPCo will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

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

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

ACQUISITIONS

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. 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 until the 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 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. PSO and SWEPCo apply the joint plant accounting model to account for their respective undivided interests in the assets, liabilities, revenues and expenses of the NCWF projects.

Rock Falls Wind Facility (Vertically Integrated Utilities Segment) (Applies to AEP and PSO)

In November 2022, PSO entered into an agreement to acquire the Rock Falls Wind Facility. In February 2023, the FERC approved PSO's acquisition of the Rock Falls Wind Facility under Section 203 of the Federal Power Act. In March 2023, PSO acquired an ownership interest in the entity that owned Rock Falls during its development and construction for $146 million. In accordance with the guidance for "Business Combinations," management determined that the acquisition of the Rock Falls Wind Facility represents an asset acquisition. The current and noncurrent Obligations Under Operating Leases related to Rock Falls were not material as of June 30, 2023. See the "2022 Oklahoma Base Rate Case" section of Note 4 for additional information.

ASSETS AND LIABILITIES HELD FOR SALE

Termination of Planned 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. The SPA was subsequently amended in September 2022 to reduce the purchase price to approximately $2.646 billion. The sale required approval from the KPSC and from the FERC under Section 203 of the Federal Power Act. The SPA contained certain termination rights if the closing of the sale did not occur by April 26, 2023.

In May 2022, the KPSC approved the sale of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. In December 2022, the FERC issued an order denying, without prejudice, authorization of the proposed sale stating the applicants failed to demonstrate the proposed transaction will not have an adverse effect on rates. In February 2023, a new filing for approval under Section 203 of the Federal Power Act was submitted. In March 2023, the KPSC and other intervenors made filings recommending the FERC reject AEP and Liberty's new Section 203 application seeking approval of the sale.

In April 2023, AEP, AEPTCo and Liberty entered into a Mutual Termination Agreement (Termination Agreement) terminating the SPA.The parties entered into the Termination Agreement as all of the conditions precedent to closing the sale could not be satisfied prior to April 26, 2023.

The impact of the Termination Agreement did not have a material impact on AEP's statements of income for the three and six months ended June 30, 2023. Upon reverting to a held and used model in the first quarter of 2023, AEP was required to present its investment in the Kentucky Operations at the lower of fair value or historical carrying value which resulted in a $335 million reduction recorded in Property, Plant and Equipment. The reduced investment in KPCo's assets is being amortized over the 30 year average useful life of the KPCo assets.

Planned Disposition of the Competitive Contracted Renewables Portfolio (Generation & Marketing Segment) (Applies to AEP)

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. As of June 30, 2023, 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 four joint venture wind farms, totaling $246 million, accounted for as equity method investments. In late January 2023, AEP received final bids from interested parties. In February 2023, AEP's Board of Directors approved management's plan to sell the competitive contracted renewables portfolio and AEP signed an agreement to sell the competitive contracted renewables portfolio to a nonaffiliated party for $1.5 billion including the assumption of project debt.

AEP expects to close on the sale in the third quarter of 2023, pending approval from the Committee on Foreign Investment in the United StatesAEP expects to receive cash proceeds, net of taxes, transaction fees and other customary closing adjustments, of approximately $1.2 billion.

Management concluded the consolidated assets within the competitive contracted renewables portfolio met the accounting requirements to be presented as Held for Sale in the first quarter of 2023 based on the receipt of final bids, Board of Director approval to consummate a sale transaction and the signing of the sale agreement. AEP recorded a pretax loss of $112 million ($88 million after-tax) in the first quarter of 2023 as a result of reaching Held for Sale status. Management concluded the impact of any other than temporary decline in the fair value of the four joint venture wind farms was not material. Any changes to the book value or carrying value of these assets, or the anticipated sale price, could further reduce future net income and impact financial condition.

The Income Before Income Tax Expense (Benefit) of the competitive contracted renewables portfolio was not material to AEP for the three and six months ended June 30, 2023 and 2022.

In March 2023, AEP ceased recognition of depreciation on the competitive contracted renewable portfolio assets due to their classification as Held for Sale on the balance sheets. The major classes of the assets and liabilities presented in Assets Held for Sale and Liabilities Held for Sale on the balance sheets of AEP are shown in the following table:

	June 30, 2023
	(in millions)
ASSETS	
Accounts Receivable and Accrued Unbilled Revenues	$ 10.0
Property, Plant and Equipment, Net	1,394.0
Other Classes of Assets that are not Major	67.3
Total Major Classes of Assets Held for Sale	1,471.3
Loss on the Expected Sale of the Competitive Contracted Renewables Portfolio (net of $23.5 million of Income Taxes)	(88.5)
Assets Held for Sale	$ 1,382.8
LIABILITIES	
Accounts Payable	$ 4.6
Asset Retirement Obligations	31.0
Obligations Under Operating Leases	21.6
Other Classes of Liabilities that are not Major	7.6
Liabilities Held for Sale	$ 64.8

The four joint venture wind farms totaling $246 million as of June 30, 2023, which are included in the plan of sale, continue to be classified as Deferred Charges and Other Noncurrent Assets and $183 million attributable to noncontrolling interests continues to be classified as Noncontrolling Interests on AEP's consolidated balance sheets.

DISPOSITIONS

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 June 2022, as a result of Flat Ridge 2's 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. In accordance with the accounting guidance for "Investments - Equity Method and Joint Ventures", in the second quarter of 2022 AEP recorded a pretax other than temporary impairment charge of $186 million which is presented 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 negotiations to sell the investment to a non-affiliate. In September 2022, AEP signed a Purchase and Sale Agreement with a nonaffiliate for AEP's interest in Flat Ridge 2. The transaction closed in the fourth quarter of 2022 and had an immaterial impact on the financial statements at closing.

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 (Credit)

Pension Plans

Three Months Ended June 30, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 23.6	$ 2.1	$ 2.2	$ 3.0	$ 2.1	$ 1.4	$ 1.9
Interest Cost	54.8	4.6	6.6	6.2	5.0	2.7	3.5
Expected Return on Plan Assets	(84.8)	(7.0)	(11.1)	(11.1)	(8.5)	(4.6)	(4.9)
Amortization of Net Actuarial Loss	0.4	—	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	$ (6.0)	$ (0.3)	$ (2.3)	$ (1.9)	$ (1.4)	$ (0.5)	$ 0.5

Three Months Ended June 30, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 30.8	$ 2.8	$ 2.8	$ 4.1	$ 2.9	$ 1.8	$ 2.7
Interest Cost	37.1	3.0	4.4	4.2	3.2	1.7	2.3
Expected Return on Plan Assets	(63.3)	(5.2)	(8.1)	(8.1)	(6.2)	(3.4)	(3.6)
Amortization of Net Actuarial Loss	15.7	1.3	1.8	1.7	1.4	0.8	0.9
Net Periodic Benefit Cost	$ 20.3	$ 1.9	$ 0.9	$ 1.9	$ 1.3	$ 0.9	$ 2.3

Six Months Ended June 30, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 47.2	$ 4.1	$ 4.5	$ 6.0	$ 4.2	$ 2.8	$ 3.8
Interest Cost	109.6	9.2	13.2	12.4	9.9	5.4	7.0
Expected Return on Plan Assets	(169.6)	(14.0)	(22.3)	(22.1)	(17.0)	(9.2)	(9.7)
Amortization of Net Actuarial Loss	0.7	—	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	$ (12.1)	$ (0.7)	$ (4.6)	$ (3.7)	$ (2.9)	$ (1.0)	$ 1.1

Six Months Ended June 30, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 61.6	$ 5.6	$ 5.7	$ 8.1	$ 5.6	$ 3.7	$ 5.3
Interest Cost	74.1	6.0	8.8	8.4	6.6	3.5	4.6
Expected Return on Plan Assets	(126.7)	(10.5)	(16.2)	(16.1)	(12.4)	(6.8)	(7.3)
Amortization of Net Actuarial Loss	31.5	2.6	3.6	3.5	2.8	1.5	1.9
Net Periodic Benefit Cost	$ 40.5	$ 3.7	$ 1.9	$ 3.9	$ 2.6	$ 1.9	$ 4.5

OPEB

Three Months Ended June 30, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1.2	$ 0.1	$ 0.2	$ 0.2	$ 0.1	$ —	$ 0.1
Interest Cost	11.5	0.9	1.9	1.4	1.1	0.6	0.7
Expected Return on Plan Assets	(27.4)	(2.2)	(4.0)	(3.4)	(3.0)	(1.4)	(1.8)
Amortization of Prior Service Credit	(15.7)	(1.4)	(2.3)	(2.1)	(1.5)	(1.0)	(1.2)
Amortization of Net Actuarial Loss	3.7	0.3	0.5	0.4	0.4	0.2	0.3
Net Periodic Benefit Credit	$ (26.7)	$ (2.3)	$ (3.7)	$ (3.5)	$ (2.9)	$ (1.6)	$ (1.9)

Three Months Ended June 30, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1.9	$ 0.1	$ 0.2	$ 0.3	$ 0.1	$ 0.1	$ 0.2
Interest Cost	7.3	0.5	1.1	0.9	0.8	0.3	0.4
Expected Return on Plan Assets	(27.5)	(2.2)	(4.0)	(3.5)	(2.9)	(1.5)	(1.8)
Amortization of Prior Service Credit	(17.9)	(1.5)	(2.6)	(2.5)	(1.8)	(1.1)	(1.3)
Net Periodic Benefit Credit	$ (36.2)	$ (3.1)	$ (5.3)	$ (4.8)	$ (3.8)	$ (2.2)	$ (2.5)

Six Months Ended June 30, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 2.3	$ 0.2	$ 0.3	$ 0.4	$ 0.2	$ 0.1	$ 0.2
Interest Cost	23.1	1.8	3.7	2.7	2.3	1.2	1.4
Expected Return on Plan Assets	(54.8)	(4.5)	(8.0)	(6.8)	(5.9)	(2.9)	(3.6)
Amortization of Prior Service Credit	(31.5)	(2.7)	(4.6)	(4.3)	(3.1)	(2.0)	(2.4)
Amortization of Net Actuarial Loss	7.4	0.6	1.1	0.9	0.8	0.4	0.5
Net Periodic Benefit Credit	$ (53.5)	$ (4.6)	$ (7.5)	$ (7.1)	$ (5.7)	$ (3.2)	$ (3.9)

Six Months Ended June 30, 2022	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 3.7	$ 0.2	$ 0.4	$ 0.5	$ 0.3	$ 0.2	$ 0.3
Interest Cost	14.6	1.1	2.3	1.7	1.5	0.7	0.9
Expected Return on Plan Assets	(55.0)	(4.5)	(8.1)	(6.9)	(5.9)	(3.0)	(3.7)
Amortization of Prior Service Credit	(35.7)	(3.0)	(5.2)	(4.9)	(3.6)	(2.2)	(2.6)
Net Periodic Benefit Credit	$ (72.4)	$ (6.2)	$ (10.6)	$ (9.6)	$ (7.7)	$ (4.3)	$ (5.1)

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, 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 tables below represent AEP's reportable segment income statement information for the three and six months ended June 30, 2023 and 2022 and reportable segment balance sheet information as of June 30, 2023 and December 31, 2022.

	Three Months Ended June 30, 2023						
	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	$ 2,629.0	$ 1,330.8	$ 88.3	$ 318.2	$ 6.2	$ —	$ 4,372.5
Other Operating Segments	45.5	9.4	370.3	13.2	25.8	(464.2)	—
Total Revenues	$ 2,674.5	$ 1,340.2	$ 458.6	$ 331.4	$ 32.0	$ (464.2)	$ 4,372.5
Net Income (Loss)	$ 278.4	$ 176.7	$ 197.3	$ (38.6)	$ (97.7)	$ —	$ 516.1

	Three Months Ended June 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	$ 2,595.0	$ 1,296.8	$ 79.1	$ 654.4	$ 14.4	$ —	$ 4,639.7
Other Operating Segments	53.5	4.8	299.7	5.2	10.1	(373.3)	—
Total Revenues	$ 2,648.5	$ 1,301.6	$ 378.8	$ 659.6	$ 24.5	$ (373.3)	$ 4,639.7
Net Income (Loss)	$ 303.3	$ 164.8	$ 142.7	$ 65.9	$ (155.9)	$ —	$ 520.8

	Six Months Ended June 30, 2023						
	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	$ 5,445.3	$ 2,786.1	$ 178.4	$ 645.1	$ 8.5	$ —	$ 9,063.4
Other Operating Segments	87.0	18.3	735.7	13.3	53.6	(907.9)	—
Total Revenues	$ 5,532.3	$ 2,804.4	$ 914.1	$ 658.4	$ 62.1	$ (907.9)	$ 9,063.4
Net Income (Loss)	$ 540.6	$ 302.4	$ 379.7	$ (195.0)	$ (111.2)	$ —	$ 916.5

	Six Months Ended June 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	$ 5,241.8	$ 2,539.0	$ 162.5	$ 1,263.9	$ 25.1	$ —	$ 9,232.3
Other Operating Segments	94.1	9.4	627.7	15.0	19.3	(765.5)	—
Total Revenues	$ 5,335.9	$ 2,548.4	$ 790.2	$ 1,278.9	$ 44.4	$ (765.5)	$ 9,232.3
Net Income (Loss)	$ 602.5	$ 317.6	$ 316.4	$ 181.9	$ (179.5)	$ —	$ 1,238.9

	June 30, 2023						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Assets (d)	$ 51,047.3	$ 23,900.0	$ 16,023.5	$ 4,457.9	$ 6,451.4 (b)	$ (5,878.0) (c)	$ 96,002.1

	December 31, 2022						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Assets	$ 49,761.8	$ 22,920.2	$ 15,215.8	$ 4,520.1	$ 6,768.4 (b)	$ (5,783.0) (c)	$ 93,403.3

(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 "Planned Disposition of the Competitive Contracted Renewables Portfolio" 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 Parent. While not considered a reportable segment, AEPTCo Parent represents the activity of the holding company which primarily relates to debt financing activity and general corporate activities.

The tables below present AEPTCo's reportable segment income statement information for the three and six months ended June 30, 2023 and 2022 and reportable segment balance sheet information as of June 30, 2023 and December 31, 2022.

	Three Months Ended June 30, 2023			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Revenues from:				
External Customers	$ 87.4	$ —	$ —	$ 87.4
Sales to AEP Affiliates	357.5	—	—	357.5
Total Revenues	$ 444.9	$ —	$ —	$ 444.9
Net Income	$ 174.2	$ 1.5 (a)	$ —	$ 175.7

	Three Months Ended June 30, 2022			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
	(in millions)			
Revenues from:				
External Customers	$ 77.3	$ —	$ —	$ 77.3
Sales to AEP Affiliates	287.1	—	—	287.1
Total Revenues	$ 364.4	$ —	$ —	$ 364.4
Net Income	$ 118.4	$ 0.1 (a)	$ —	$ 118.5

	Six Months Ended June 30, 2023			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 176.4	$ —	$ —	$ 176.4
Sales to AEP Affiliates	710.1	—	—	710.1
Total Revenues	$ 886.5	$ —	$ —	$ 886.5
Net Income	$ 335.8	$ 2.6 (a)	$ —	$ 338.4

	Six Months Ended June 30, 2022			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 162.3	$ —	$ —	$ 162.3
Sales to AEP Affiliates	602.5	—	—	602.5
Total Revenues	$ 764.8	$ —	$ —	$ 764.8
Net Income	$ 273.8	$ 0.1 (a)	$ —	$ 273.9

	June 30, 2023			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets	$ 14,626.3	$ 5,542.1 (b)	$ (5,591.9) (c)	$ 14,576.5

	December 31, 2022			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets	$ 13,875.6	$ 4,817.4 (b)	$ (4,878.8) (c)	$ 13,814.2

(a) Includes the elimination of AEPTCo Parent's equity earnings in the State Transcos.
(b) Primarily relates to Notes Receivable from the State Transcos.
(c) Primarily relates to the elimination of Notes Receivable from the State Transcos.

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

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

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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
June 30, 2023

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	269.9	—	29.1	9.2	2.3	8.7	6.9
Natural Gas	MMBtus	136.8	—	5.2	—	—	28.3	7.3
Heating Oil and Gasoline	Gallons	6.7	1.8	1.0	0.6	1.4	0.9	0.9
Interest Rate	USD	$ 91.4	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 950.0	$ —	$ —	$ —	$ —	$ —	$ —

December 31, 2022

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	226.8	—	17.9	4.2	2.5	2.9	2.2
Natural Gas	MMBtus	77.1	—	1.9	—	—	1.9	2.1
Heating Oil and Gasoline	Gallons	6.9	1.9	1.0	0.7	1.4	0.9	1.0
Interest Rate	USD	$ 99.9	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt	USD	$ 1,650.0	$ —	$ —	$ —	$ —	$ 200.0	$ —

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 $73 million and $481 million as of June 30, 2023 and December 31, 2022, respectively. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $35 million and $2 million as of June 30, 2023 and December 31, 2022, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for the Registrant Subsidiaries as of June 30, 2023 and December 31, 2022.The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was immaterial for the Registrant Subsidiaries as of June 30, 2023 and December 31, 2022.

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

	June 30, 2023					
	Risk Management Contracts	Hedging Contracts				
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$ 721.6	$ 43.4	$ —	$ 765.0	$ (485.5)	$ 279.5
Long-term Risk Management Assets	466.4	95.1	—	561.5	(294.7)	266.8
Total Assets	1,188.0	138.5	—	1,326.5	(780.2)	546.3
Current Risk Management Liabilities	631.5	12.8	42.6	686.9	(510.7)	176.2
Long-term Risk Management Liabilities	418.5	6.7	82.1	507.3	(232.0)	275.3
Total Liabilities	1,050.0	19.5	124.7	1,194.2	(742.7)	451.5
Total MTM Derivative Contract Net Assets (Liabilities)	$ 138.0	$ 119.0	$ (124.7)	$ 132.3	$ (37.5)	$ 94.8

	December 31, 2022					
	Risk Management Contracts	Hedging Contracts				
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)					
Current Risk Management Assets	$ 965.4	$ 212.2	$ 1.8	$ 1,179.4	$ (830.6)	$ 348.8
Long-term Risk Management Assets	565.6	148.9	14.3	728.8	(444.7)	284.1
Total Assets	1,531.0	361.1	16.1	1,908.2	(1,275.3)	632.9
Current Risk Management Liabilities	663.8	60.4	41.4	765.6	(620.4)	145.2
Long-term Risk Management Liabilities	412.0	17.4	91.1	520.5	(175.3)	345.2
Total Liabilities	1,075.8	77.8	132.5	1,286.1	(795.7)	490.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 455.2	$ 283.3	$ (116.4)	$ 622.1	$ (479.6)	$ 142.5

AEP Texas

Balance Sheet Location	June 30, 2023 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	0.4	(0.4)	—
Long-term Risk Management Liabilities	0.1	(0.1)	—
Total Liabilities	0.5	(0.5)	—
Total MTM Derivative Contract Net Assets (Liabilities)	$ (0.5)	$ 0.5	$ —

Balance Sheet Location	December 31, 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	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$ —	$ —	$ —

APCo

Balance Sheet Location	June 30, 2023 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	$ 42.5	$ (3.3)	$ 39.2
Long-term Risk Management Assets	0.6	(0.4)	0.2
Total Assets	43.1	(3.7)	39.4
Current Risk Management Liabilities	5.1	(4.0)	1.1
Long-term Risk Management Liabilities	0.4	(0.4)	—
Total Liabilities	5.5	(4.4)	1.1
Total MTM Derivative Contract Net Assets	$ 37.6	$ 0.7	$ 38.3

Balance Sheet Location	December 31, 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	$ 69.3	$ (0.2)	$ 69.1
Long-term Risk Management Assets	0.7	(0.7)	—
Total Assets	70.0	(0.9)	69.1
Current Risk Management Liabilities	4.1	(0.5)	3.6
Long-term Risk Management Liabilities	0.7	(0.6)	0.1
Total Liabilities	4.8	(1.1)	3.7
Total MTM Derivative Contract Net Assets	$ 65.2	$ 0.2	$ 65.4

I&M

Balance Sheet Location	June 30, 2023 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	$ 22.3	$ (0.9)	$ 21.4
Long-term Risk Management Assets	11.8	(2.7)	9.1
Total Assets	34.1	(3.6)	30.5
Current Risk Management Liabilities	2.8	(1.4)	1.4
Long-term Risk Management Liabilities	2.7	(2.7)	—
Total Liabilities	5.5	(4.1)	1.4
Total MTM Derivative Contract Net Assets	$ 28.6	$ 0.5	$ 29.1

Balance Sheet Location	December 31, 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	$ 16.0	$ (0.8)	$ 15.2
Long-term Risk Management Assets	0.5	(0.3)	0.2
Total Assets	16.5	(1.1)	15.4
Current Risk Management Liabilities	0.9	(0.9)	—
Long-term Risk Management Liabilities	0.3	(0.3)	—
Total Liabilities	1.2	(1.2)	—
Total MTM Derivative Contract Net Assets	$ 15.3	$ 0.1	$ 15.4

OPCo

Balance Sheet Location	June 30, 2023 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	6.6	(0.3)	6.3
Long-term Risk Management Liabilities	47.8	(0.1)	47.7
Total Liabilities	54.4	(0.4)	54.0
Total MTM Derivative Contract Net Assets (Liabilities)	$ (54.4)	$ 0.4	$ (54.0)

Balance Sheet Location	December 31, 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	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	2.1	(0.3)	1.8
Long-term Risk Management Liabilities	37.9	—	37.9
Total Liabilities	40.0	(0.3)	39.7
Total MTM Derivative Contract Net Assets (Liabilities)	$ (40.0)	$ 0.3	$ (39.7)

PSO

Balance Sheet Location	June 30, 2023 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	$ 47.4	$ (2.6)	$ 44.8
Long-term Risk Management Assets	0.2	(0.2)	—
Total Assets	47.6	(2.8)	44.8
Current Risk Management Liabilities	5.4	(2.8)	2.6
Long-term Risk Management Liabilities	1.0	(0.2)	0.8
Total Liabilities	6.4	(3.0)	3.4
Total MTM Derivative Contract Net Assets	$ 41.2	$ 0.2	$ 41.4

Balance Sheet Location	December 31, 2022 Risk Management Contracts – Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)		
Current Risk Management Assets	$ 24.1	$ 1.6	$ 25.7	$ (0.4)	$ 25.3
Long-term Risk Management Assets	—	—	—	—	—
Total Assets	24.1	1.6	25.7	(0.4)	25.3
Current Risk Management Liabilities	2.1	—	2.1	(0.5)	1.6
Long-term Risk Management Liabilities	—	—	—	—	—
Total Liabilities	2.1	—	2.1	(0.5)	1.6
Total MTM Derivative Contract Net Assets	$ 22.0	$ 1.6	$ 23.6	$ 0.1	$ 23.7

SWEPCo

Balance Sheet Location	June 30, 2023 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	$ 28.5	$ (0.5)	$ 28.0
Long-term Risk Management Assets	—	—	—
Total Assets	28.5	(0.5)	28.0
Current Risk Management Liabilities	2.4	(0.8)	1.6
Long-term Risk Management Liabilities	0.2	—	0.2
Total Liabilities	2.6	(0.8)	1.8
Total MTM Derivative Contract Net Assets	$ 25.9	$ 0.3	$ 26.2

Balance Sheet Location	December 31, 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	$ 16.8	$ (0.4)	$ 16.4
Long-term Risk Management Assets	—	—	—
Total Assets	16.8	(0.4)	16.4
Current Risk Management Liabilities	2.0	(0.6)	1.4
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	2.0	(0.6)	1.4
Total MTM Derivative Contract Net Assets	$ 14.8	$ 0.2	$ 15.0

(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.

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 June 30, 2023 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ 17.0	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(141.8)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	—	17.0	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1.3	—	1.3	0.1	—	—	—
Other Operation	(0.1)	—	—	—	—	—	—
Maintenance	(0.3)	(0.1)	—	—	—	—	—
Regulatory Assets (a)	(12.4)	(0.1)	5.9	(1.6)	(12.8)	(2.3)	(0.9)
Regulatory Liabilities (a)	102.0	—	17.4	3.6	—	42.4	33.6
Total Gain (Loss) on Risk Management Contracts	$ (34.3)	$ (0.2)	$ 24.6	$ 19.1	$ (12.8)	$ 40.1	$ 32.7

Location of Gain (Loss)	Three Months Ended June 30, 2022 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ 0.1	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	121.0	—	—	—	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	0.9	—	0.7	—	—	0.1	—
Other Operation	1.7	0.5	0.2	0.2	0.3	0.2	0.3
Maintenance	2.4	0.7	0.4	0.2	0.4	0.3	0.4
Regulatory Assets (a)	21.4	0.1	0.1	0.3	21.0	—	(0.1)
Regulatory Liabilities (a)	110.4	—	21.6	1.5	1.6	39.0	36.9
Total Gain on Risk Management Contracts	$ 257.9	$ 1.3	$ 23.0	$ 2.2	$ 23.3	$ 39.6	$ 37.5

Location of Gain (Loss)	Six Months Ended June 30, 2023 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 11.7	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(289.2)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	—	11.7	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	2.0	—	1.9	0.1	—	—	—
Other Operation	(0.1)	—	—	—	—	—	—
Maintenance	(0.2)	(0.1)	—	—	—	—	—
Regulatory Assets (a)	(37.2)	(0.5)	(1.2)	(2.1)	(25.1)	(3.5)	(2.4)
Regulatory Liabilities (a)	100.5	—	(8.8)	4.8	—	60.4	45.5
Total Gain (Loss) on Risk Management Contracts	$ (212.5)	$ (0.6)	$ (8.1)	$ 14.5	$ (25.1)	$ 56.9	$ 43.1

Location of Gain (Loss)	Six Months Ended June 30, 2022 AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 0.1	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	273.3	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	(0.1)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	2.4	—	2.1	—	—	0.1	—
Other Operation	2.3	0.7	0.2	0.3	0.4	0.3	0.4
Maintenance	3.2	0.9	0.5	0.3	0.5	0.4	0.5
Regulatory Assets (a)	45.0	0.1	—	(1.3)	44.9	3.6	(2.2)
Regulatory Liabilities (a)	146.9	0.9	20.2	3.2	1.6	51.7	57.8
Total Gain on Risk Management Contracts	$ 473.2	$ 2.6	$ 23.1	$ 2.4	$ 47.4	$ 56.1	$ 56.5

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same 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	
	June 30, 2023	**December 31, 2022**	**June 30, 2023**	**December 31, 2022**
		(in millions)		
Long-term Debt (a) (b)	$ (855.1)	$ (855.5)	$ 90.8	$ 89.7

(a) Amounts included on the Balance Sheet within Noncurrent Liabilities line item Long-term Debt.
(b) Amounts include $(34) million and $(38) million as of June 30, 2023 and December 31, 2022, 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 June 30,		Six Months Ended June 30,	
	2023	**2022**	**2023**	**2022**
		(in millions)		
Gain (Loss) on Interest Rate Contracts:				
Fair Value Hedging Instruments (a)	$ (4.2)	$ (17.6)	$ 2.7	$ (62.4)
Fair Value Portion of Long-term Debt (a)	4.2	17.6	(2.7)	62.4

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

Accounting for Cash Flow Hedging Strategies (Applies to AEP, AEP Texas, APCo, I&M, PSO 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 six months ended June 30, 2023 and 2022, 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 months ended June 30, 2023, AEP and AEP Texas applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the six months ended June 30, 2023, AEP, AEP Texas, I&M, PSO and SWEPCo applied cash flow hedging t outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the three and six months ended June 30, 2022, AEP applied cash flow hedging to outstanding interest rate derivatives and the Registrant Subsidiaries did not.

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

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

Impact of Cash Flow Hedges on AEP's Balance Sheets

	June 30, 2023		December 31, 2022	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain Net of Tax	$ 93.5	$ 12.7	$ 223.5	$ 0.3
Portion Expected to be Reclassed to Net Income During the Next Twelve Months	24.1	4.3	119.9	0.3

As of June 30, 2023 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 93 months and 90 months for commodity and interest rate hedges, respectively.

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

	June 30, 2023		December 31, 2022	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ 2.9	$ 0.3	$ (0.3)	$ (0.2)
APCo	6.3	0.8	6.7	0.8
I&M	(5.7)	(0.4)	(5.1)	(0.6)
PSO	(0.2)	—	1.3	0.1
SWEPCo	1.4	0.3	1.1	0.2

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 $0 and $2 million as of June 30, 2023 and December 31, 2022, respectively. The Registrant Subsidiaries had no derivative contracts with collateral triggering events in a net liability position as of June 30, 2023 and December 31, 2022.

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 $125 million and $127 million as of June 30, 2023 and December 31, 2022, respectively. There was no cash collateral posted as of June 30, 2023 and December 31, 2022, 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 June 30, 2023 and December 31, 2022.

Cross-Default Triggers (Applies to AEP, APCo, I&M, PSO 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 $178 million and $217 million as of June 30, 2023 and December 31, 2022, respectively, after considering contractual netting arrangements. There was no cash collateral posted as of June 30, 2023 and December 31, 2022.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 June 30, 2023 and December 31, 2022 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:

	June 30, 2023		December 31, 2022	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
		(in millions)		
AEP (a)	$ 40,142.3	$ 36,351.3	$ 36,801.0	$ 32,915.9
AEP Texas	5,937.5	5,295.5	5,657.8	5,045.8
AEPTCo	5,473.0	4,719.2	4,782.8	3,940.5
APCo	5,599.7	5,298.4	5,410.5	5,079.2
I&M	3,464.1	3,174.2	3,260.8	2,929.0
OPCo	3,365.6	2,878.8	2,970.3	2,516.6
PSO	2,383.9	2,106.1	1,912.8	1,635.8
SWEPCo	3,645.6	3,135.3	3,391.6	2,870.9

(a) The fair value amounts include debt related to AEP's Equity Units and had a fair value of $844 million and $877 million as of June 30, 2023 and December 31, 2022, respectively. See "Equity Units" section of Note 12 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:

	June 30, 2023			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
		(in millions)		
Restricted Cash (a)	$ 45.8	$ —	$ —	$ 45.8
Other Cash Deposits	15.9	—	—	15.9
Fixed Income Securities – Mutual Funds (b)	155.7	—	(8.9)	146.8
Equity Securities – Mutual Funds	15.4	24.4	—	39.8
Total Other Temporary Investments and Restricted Cash	$ 232.8	$ 24.4	$ (8.9)	$ 248.3

Other Temporary Investments and Restricted Cash	December 31, 2022 Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$ 47.1	$ —	$ —	$ 47.1
Other Cash Deposits	9.0	—	—	9.0
Fixed Income Securities – Mutual Funds (b)	152.4	—	(8.3)	144.1
Equity Securities – Mutual Funds	15.1	19.4	—	34.5
Total Other Temporary Investments and Restricted Cash	$ 223.6	$ 19.4	$ (8.3)	$ 234.7

(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 June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(in millions)			
Proceeds from Investment Sales	$ —	$ 11.1	$ —	$ 15.0
Purchases of Investments	1.3	0.8	2.3	1.6
Gross Realized Gains on Investment Sales	—	3.3	—	3.6
Gross Realized Losses on Investment Sales	—	0.4	—	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 genera risk management guidelines. In general, limitations include:

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

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by 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:

	June 30, 2023				December 31, 2022			
	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments
	(in millions)							
Cash and Cash Equivalents	$ 24.2	$ —	$ —	$ —	$ 21.2	$ —	$ —	$ —
Fixed Income Securities:								
United States Government	1,191.9	9.9	(13.8)	(25.6)	1,123.8	11.8	(14.9)	(18.8)
Corporate Debt	68.8	0.8	(6.6)	(1.7)	61.6	0.7	(7.7)	(9.6)
State and Local Government	3.3	—	—	—	3.3	0.1	—	(0.1)
Subtotal Fixed Income Securities	1,264.0	10.7	(20.4)	(27.3)	1,188.7	12.6	(22.6)	(28.5)
Equity Securities - Domestic	2,360.6	1,725.7	(4.6)	—	2,131.3	1,483.7	(6.4)	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 3,648.8	$ 1,736.4	$ (25.0)	$ (27.3)	$ 3,341.2	$ 1,496.3	$ (29.0)	$ (28.5)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in millions)			
Proceeds from Investment Sales	$ 688.7	$ 736.4	$ 1,206.3	$ 1,229.9
Purchases of Investments	697.0	745.5	1,233.3	1,253.2
Gross Realized Gains on Investment Sales	6.4	10.9	54.8	16.7
Gross Realized Losses on Investment Sales	3.7	17.9	12.3	25.1

The base cost of fixed income securities was $1.3 billion and $1.2 billion as of June 30, 2023 and December 31, 2022, respectively. The base cost of equity securities was $640 million and $654 million as of June 30, 2023 and December 31, 2022, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of June 30, 2023 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 325.0
After 1 year through 5 years	496.9
After 5 years through 10 years	219.2
After 10 years	222.9
Total	$ 1,264.0

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
June 30, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 45.8	$ —	$ —	$ —	$ 45.8
Other Cash Deposits (a)	—	—	—	15.9	15.9
Fixed Income Securities – Mutual Funds	146.8	—	—	—	146.8
Equity Securities – Mutual Funds (b)	39.8	—	—	—	39.8
Total Other Temporary Investments and Restricted Cash	232.4	—	—	15.9	248.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	12.5	893.6	276.5	(756.9)	425.7
Cash Flow Hedges:					
Commodity Hedges (c)	—	118.4	19.4	(17.2)	120.6
Total Risk Management Assets	12.5	1,012.0	295.9	(774.1)	546.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	13.3	—	—	10.9	24.2
Fixed Income Securities:					
United States Government	—	1,191.9	—	—	1,191.9
Corporate Debt	—	68.8	—	—	68.8
State and Local Government	—	3.3	—	—	3.3
Subtotal Fixed Income Securities	—	1,264.0	—	—	1,264.0
Equity Securities – Domestic (b)	2,360.6	—	—	—	2,360.6
Total Spent Nuclear Fuel and Decommissioning Trusts	2,373.9	1,264.0	—	10.9	3,648.8
Total Assets	$ 2,618.8	$ 2,276.0	$ 295.9	$ (747.3)	$ 4,443.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 26.5	$ 848.3	$ 169.8	$ (719.4)	$ 325.2
Cash Flow Hedges:					
Commodity Hedges (c)	—	18.8	—	(17.2)	1.6
Fair Value Hedges	—	124.7	—	—	124.7
Total Risk Management Liabilities	$ 26.5	$ 991.8	$ 169.8	$ (736.6)	$ 451.5

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 47.1	$ —	$ —	$ —	$ 47.1
Other Cash Deposits (a)	—	—	—	9.0	9.0
Fixed Income Securities – Mutual Funds	144.1	—	—	—	144.1
Equity Securities – Mutual Funds (b)	34.5	—	—	—	34.5
Total Other Temporary Investments and Restricted Cash	225.7	—	—	9.0	234.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	15.0	1,197.5	314.4	(1,211.5)	315.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	332.6	26.7	(52.8)	306.5
Interest Rate Hedges	—	11.0	—	—	11.0
Total Risk Management Assets	15.0	1,541.1	341.1	(1,264.3)	632.9
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	11.3	—	—	9.9	21.2
Fixed Income Securities:					
United States Government	—	1,123.8	—	—	1,123.8
Corporate Debt	—	61.6	—	—	61.6
State and Local Government	—	3.3	—	—	3.3
Subtotal Fixed Income Securities	—	1,188.7	—	—	1,188.7
Equity Securities – Domestic (b)	2,131.3	—	—	—	2,131.3
Total Spent Nuclear Fuel and Decommissioning Trusts	2,142.6	1,188.7	—	9.9	3,341.2
Total Assets	$ 2,383.3	$ 2,729.8	$ 341.1	$ (1,245.4)	$ 4,208.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 21.8	$ 870.9	$ 179.0	$ (731.9)	$ 339.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	74.3	1.7	(52.8)	23.2
Fair Value Hedges	—	127.4	—	—	127.4
Total Risk Management Liabilities	$ 21.8	$ 1,072.6	$ 180.7	$ (784.7)	$ 490.4

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 30.7	$ —	$ —	$ —	$ 30.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.5	$ —	$ (0.5)	$ —

December 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 32.7	$ —	$ —	$ —	$ 32.7

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 15.1	$ —	$ —	$ —	$ 15.1
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	1.6	41.1	(3.3)	39.4
Total Assets	$ 15.1	$ 1.6	$ 41.1	$ (3.3)	$ 54.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 3.4	$ 1.7	$ (4.0)	$ 1.1

December 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 14.4	$ —	$ —	$ —	$ 14.4
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	0.7	69.4	(1.0)	69.1
Total Assets	$ 14.4	$ 0.7	$ 69.4	$ (1.0)	$ 83.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 4.6	$ 0.3	$ (1.4)	$ 3.5

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 25.6	$ 8.2	$ (3.3)	$ 30.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	13.3	—	—	10.9	24.2
Fixed Income Securities:					
United States Government	—	1,191.9	—	—	1,191.9
Corporate Debt	—	68.8	—	—	68.8
State and Local Government	—	3.3	—	—	3.3
Subtotal Fixed Income Securities	—	1,264.0	—	—	1,264.0
Equity Securities - Domestic (b)	2,360.6	—	—	—	2,360.6
Total Spent Nuclear Fuel and Decommissioning Trusts	2,373.9	1,264.0	—	10.9	3,648.8
Total Assets	$ 2,373.9	$ 1,289.6	$ 8.2	$ 7.6	$ 3,679.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 3.8	$ 1.4	$ (3.8)	$ 1.4

December 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 11.3	$ 5.3	$ (1.2)	$ 15.4
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	11.3	—	—	9.9	21.2
Fixed Income Securities:					
United States Government	—	1,123.8	—	—	1,123.8
Corporate Debt	—	61.6	—	—	61.6
State and Local Government	—	3.3	—	—	3.3
Subtotal Fixed Income Securities	—	1,188.7	—	—	1,188.7
Equity Securities - Domestic (b)	2,131.3	—	—	—	2,131.3
Total Spent Nuclear Fuel and Decommissioning Trusts	2,142.6	1,188.7	—	9.9	3,341.2
Total Assets	$ 2,142.6	$ 1,200.0	$ 5.3	$ 8.7	$ 3,356.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.6	$ 0.7	$ (1.3)	$ —

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2023

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.4	$ 54.0	$ (0.4)	$ 54.0

December 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 40.0	$ (0.3)	$ 39.7

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 2.9	$ 44.7	$ (2.8)	$ 44.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 4.8	$ 1.6	$ (3.0)	$ 3.4

December 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 24.0	$ 1.3	$ 25.3
Cash Flow Hedges:					
Interest Rate Hedges	—	1.6	—	(1.6)	—
Total Assets	$ —	$ 1.6	$ 24.0	$ (0.3)	$ 25.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 1.7	$ 0.3	$ (0.4)	$ 1.6

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.4	$ 28.1	$ (0.5)	$ 28.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.5	$ 2.1	$ (0.8)	$ 1.8

December 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 2.2	$ 14.6	$ (0.4)	$ 16.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 1.6	$ 0.4	$ (0.6)	$ 1.4

(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 June 30, 2023 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $(6) million in 2023 and $(8) million in periods 2024-2026; Level 2 matures $(27) million in 2023, $59 million in periods 2024-2026, $12 million in periods 2027-2028 and $2 million in periods 2029-2033; Level 3 matures $63 million in 2023, $56 million in periods 2024-2026, $1 million in periods 2027-2028 and $(14) million in periods 2029-2033. 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, 2022 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $(7) million in 2023; Level 2 matures $182 million in 2023, $134 million in periods 2024-2026, $10 million in periods 2027-2028 and $1 million in periods 2029-2033; Level 3 matures $128 million in 2023, $6 million in periods 2024-2026, $6 million in periods 2027-2028 and $(5) million in periods 2029-2033. Risk management commodity contracts are substantially comprised of power contracts.
(g) Substantially comprised of power contracts for the Registrant Subsidiaries.

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

Three Months Ended June 30, 2023	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of March 31, 2023	$ 45.1	$ 5.7	$ 1.1	$ (46.9)	$ 9.3	$ 5.8
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(86.8)	(11.9)	(3.2)	(1.4)	(42.1)	(32.8)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(15.8)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	4.7	—	—	—	—	—
Settlements	62.3	6.2	2.0	1.3	32.8	27.0
Transfers out of Level 3 (e)	(3.1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	119.7	39.4	6.9	(7.0)	43.1	26.0
Balance as of June 30, 2023	$ 126.1	$ 39.4	$ 6.8	$ (54.0)	$ 43.1	$ 26.0

Three Months Ended June 30, 2022	AEP	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)					
Balance as of March 31, 2022	$ 82.8	$ 6.6	$ 1.0	$ (68.5)	$ 6.5	$ 15.7
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	38.6	5.7	(0.3)	0.9	11.9	19.9
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(16.8)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	5.7	—	—	—	—	—
Settlements	(69.3)	(12.4)	(0.7)	—	(18.4)	(27.9)
Transfers into Level 3 (d) (e)	2.4	—	—	—	—	—
Transfers out of Level 3 (e)	5.8	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	234.7	79.7	9.8	19.2	64.5	37.7
Balance as of June 30, 2022	$ 283.9	$ 79.6	$ 9.8	$ (48.4)	$ 64.5	$ 45.4

Six Months Ended June 30, 2023	AEP	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)		
Balance as of December 31, 2022	$ 160.4	$ 69.1	$ 4.6	$ (40.0)	$ 23.7	$ 14.2
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(97.5)	(47.9)	(2.3)	(1.7)	(25.5)	(20.3)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(3.0)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(15.0)	—	—	—	—	—
Settlements	(23.0)	(21.1)	(2.2)	2.4	1.8	6.1
Transfers into Level 3 (d) (e)	(6.1)	—	—	—	—	—
Transfers out of Level 3 (e)	(1.3)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	111.6	39.3	6.7	(14.7)	43.1	26.0
Balance as of June 30, 2023	$ 126.1	$ 39.4	$ 6.8	$ (54.0)	$ 43.1	$ 26.0

Six Months Ended June 30, 2022	AEP	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)		
Balance as of December 31, 2021	$ 103.1	$ 41.7	$ (0.7)	$ (92.5)	$ 12.1	$ 10.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	68.1	3.0	3.7	2.4	24.2	32.5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(35.7)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	22.5	—	—	—	—	—
Settlements	(149.0)	(44.7)	(3.0)	1.4	(36.3)	(41.0)
Transfers into Level 3 (d) (e)	4.4	—	—	—	—	—
Transfers out of Level 3 (e)	9.6	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	260.9	79.6	9.8	40.3	64.5	43.0
Balance as of June 30, 2022	$ 283.9	$ 79.6	$ 9.8	$ (48.4)	$ 64.5	$ 45.4

(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.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
June 30, 2023

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Weighted Average (c)
		(in millions)						
AEP	Energy Contracts	$ 158.4	$ 158.1	Discounted Cash Flow	Forward Market Price (a)	$ 1.89	$ 90.40	$ 44.95
AEP	Natural Gas Contracts	0.2	0.2	Discounted Cash Flow	Forward Market Price (b)	2.14	4.21	3.21
AEP	FTRs	137.3	11.5	Discounted Cash Flow	Forward Market Price (a)	(17.92)	11.35	(0.20)
APCo	Natural Gas Contracts	0.2	—	Discounted Cash Flow	Forward Market Price (b)	2.91	4.19	3.35
APCo	FTRs	40.9	1.7	Discounted Cash Flow	Forward Market Price (a)	(3.60)	9.53	1.37
I&M	FTRs	8.2	1.4	Discounted Cash Flow	Forward Market Price (a)	(6.02)	9.11	1.07
OPCo	Energy Contracts	—	54.0	Discounted Cash Flow	Forward Market Price (a)	16.97	71.80	41.40
PSO	FTRs	44.7	1.6	Discounted Cash Flow	Forward Market Price (a)	(17.92)	0.87	(4.44)
SWEPCo	Natural Gas Contracts	—	0.2	Discounted Cash Flow	Forward Market Price (b)	2.91	4.19	3.35
SWEPCo	FTRs	28.1	1.9	Discounted Cash Flow	Forward Market Price (a)	(17.92)	0.87	(4.44)

December 31, 2022

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Weighted Average (c)
		(in millions)						
AEP	Energy Contracts	$ 204.0	$ 167.4	Discounted Cash Flow	Forward Market Price	$ 2.91	$ 187.34	$ 49.14
AEP	FTRs	137.1	13.3	Discounted Cash Flow	Forward Market Price	(36.45)	20.72	1.18
APCo	FTRs	69.4	0.3	Discounted Cash Flow	Forward Market Price	(2.82)	18.88	3.89
I&M	FTRs	5.3	0.7	Discounted Cash Flow	Forward Market Price	0.16	18.79	1.23
OPCo	Energy Contracts	—	40.0	Discounted Cash Flow	Forward Market Price	2.91	187.34	48.76
PSO	FTRs	24.0	0.3	Discounted Cash Flow	Forward Market Price	(36.45)	3.40	(7.55)
SWEPCo	FTRs	14.6	0.4	Discounted Cash Flow	Forward Market Price	(36.45)	3.40	(7.55)

(a) Represents market prices in dollars per MWh.
(b) Represents market prices in dollars per MMBtu.
(c) The weighted average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs for the Registrants as of June 30, 2023 and December 31, 2022:

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 2023 and 2022, 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 June 30, 2023							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	2.1 %	0.6 %	2.6 %	3.2 %	0.7 %	0.8 %	2.0 %	(1.6) %
Tax Reform Excess ADIT Reversal	(6.2)%	(1.3)%	0.1 %	(4.5)%	(6.1)%	(8.5)%	(17.2)%	(4.2) %
Production and Investment Tax Credits	(9.9)%	(0.2)%	— %	(0.1)%	0.1 %	—%	(55.1)%	(29.2) %
Flow Through	(1.0)%	0.1 %	0.2 %	(5.1)%	(4.4)%	1.2 %	0.3 %	(0.8) %
AFUDC Equity	(1.2)%	(0.9)%	(2.1) %	(1.5)%	(0.1)%	(0.7)%	(1.4)%	— %
Other	0.4 %	0.3 %	— %	(0.4)%	0.1 %	0.1 %	—%	0.7 %
Effective Income Tax Rate	5.2 %	19.6 %	21.8 %	12.6 %	11.3 %	13.9 %	(50.4)%	(14.1) %

	Three Months Ended June 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	1.3 %	0.7 %	2.9 %	(1.0)%	(1.3)%	1.0 %	3.9 %	2.5 %
Tax Reform Excess ADIT Reversal	(7.1)%	(2.1)%	0.3 %	(20.4)%	(17.2)%	(7.8)%	(19.2)%	(5.2) %
Production and Investment Tax Credits	(6.1)%	(0.6)%	— %	—%	(3.4)%	—%	(32.2)%	(19.8) %
Flow Through	(0.1)%	0.2 %	0.4 %	(1.4)%	(1.2)%	0.2 %	0.3 %	— %
AFUDC Equity	(1.1)%	(1.4)%	(2.3) %	(1.5)%	(1.3)%	(0.7)%	(0.4)%	(0.5) %
Discrete Tax Adjustments	0.3 %	—%	— %	(6.0)%	—%	—%	—%	0.8 %
Other	1.1 %	0.1 %	0.1 %	(0.2)%	1.3 %	0.1 %	0.5 %	(0.1) %
Effective Income Tax Rate	9.3 %	17.9 %	22.4 %	(9.5)%	(2.1)%	13.8 %	(26.1)%	(1.3) %

	Six Months Ended June 30, 2023							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
U.S. Federal Statutory Rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State Income Tax, net of Federal Benefit	2.0 %	0.5 %	2.6 %	2.6 %	2.4 %	0.9 %	2.0 %	(1.2) %
Tax Reform Excess ADIT Reversal	(6.2)%	(1.4)%	0.2 %	(4.5)%	(7.2)%	(7.6)%	(17.1)%	(4.0) %
Production and Investment Tax Credits	(9.8)%	(0.2)%	— %	(0.1)%	(0.6)%	—%	(55.2)%	(28.2) %
Flow Through	(0.5)%	0.2 %	0.2 %	(0.8)%	(2.9)%	0.8 %	0.3 %	(0.3) %
AFUDC Equity	(1.3)%	(1.1)%	(1.8) %	(0.9)%	(0.3)%	(0.8)%	(1.4)%	(0.3) %
Discrete Tax Adjustments	(1.4)%	—%	— %	2.4 %	1.0 %	—%	—%	— %
Other	0.3 %	0.2 %	— %	(0.1)%	0.1 %	0.1 %	0.1 %	0.1 %
Effective Income Tax Rate	4.1 %	19.2 %	22.2 %	19.6 %	13.5 %	14.4 %	(50.3)%	(12.9) %

	Six Months Ended June 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	1.4 %	0.5 %	2.7 %	1.5 %	0.4 %	0.9 %	3.5 %	2.4 %
Tax Reform Excess ADIT Reversal	(6.8)%	(2.0)%	0.3 %	(11.0)%	(17.2)%	(7.8)%	(18.6)%	(5.1) %
Production and Investment Tax Credits	(7.1)%	(0.4)%	— %	—%	(2.3)%	—%	(31.4)%	(20.8) %
Flow Through	0.1 %	0.2 %	0.3 %	0.6 %	(1.6)%	0.6 %	0.3 %	(0.2) %
AFUDC Equity	(1.0)%	(1.1)%	(1.9) %	(1.0)%	(0.9)%	(0.6)%	(0.5)%	(0.5) %
Discrete Tax Adjustments	(0.2)%	—%	— %	(2.6)%	—%	—%	—%	0.5 %
Other	0.5 %	(0.1)%	0.2 %	—%	0.4 %	(0.1)%	0.3 %	— %
Effective Income Tax Rate	7.9 %	18.1 %	22.6 %	8.5 %	(0.2)%	14.0 %	(25.4)%	(2.7) %

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. AEP has agreed to extend the statute of limitations on the 2017-2019 tax returns to October 31, 2024, to allow time for the current IRS audit to be completed including a refund claim approval by the Congressional Joint Committee on Taxation. The statute of limitations for the 2020 return is set to naturally expire in October 2024 as well.

The current IRS audit and associated refund claim evolved from a net operating loss carryback to 2015 that originated in the 2017 return. AEP has received and agreed to two IRS proposed adjustments on the 2017 tax return, which were immaterial. The exam is nearly complete, and AEP is currently working with the IRS to submit the refund claim to the Congressional Joint Committee on Taxation for resolution and final approval.

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

In August 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. As further 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.

In December 2022, the IRS released Notice 2023-7 addressing time sensitive issues related to the CAMT.The notice provided initial guidance that AEP can begin to rely on in 2023 and also stated that additional guidance is expected, of which AEP will continue to monitor and assess. Notably, the interim guidance in Notice 2023-7 confirmed the CAMT depreciation adjustment includes tax depreciation that is capitalized to inventory under §263A and recovered as part of cost of goods sold, providing significant relief to AEP's potential CAMT exposure.

AEP and subsidiaries expect to be applicable corporations for purposes of the CAMT beginning in 2023.CAMT cash taxes are expected to be partially offset by regulatory recovery, the utilization of tax credits and additionally the cash inflow generated by the sale of tax credits. The sale of tax credits will be presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. AEP will present the gain or loss on sale of tax credits through income tax expense.

In June 2023, the IRS issued temporary regulations related to the transfer of tax credits.AEP and subsidiaries have qualifying tax credits that are eligible to be transferred and, depending on market conditions, will consider selling qualifying tax credits in the second half of 2023.

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 six months ended June 30, 2023.

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	June 30, 2023	December 31, 2022
	(in millions)	
Senior Unsecured Notes	$ 33,491.5	$ 30,174.8
Pollution Control Bonds	1,770.9	1,770.2
Notes Payable	165.8	269.7
Securitization Bonds	432.1	487.8
Spent Nuclear Fuel Obligation (a)	292.3	285.6
Junior Subordinated Notes (b)	2,385.0	2,381.3
Other Long-term Debt	1,604.7	1,431.6
Total Long-term Debt Outstanding	40,142.3	36,801.0
Long-term Debt Due Within One Year	3,380.3	2,486.4
Long-term Debt	$ 36,762.0	$ 34,314.6

(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 $341 million and $330 million as of June 30, 2023 and December 31, 2022, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.
(b) See "Equity Units" section below for additional information.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first six months of 2023 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		**(in millions)**	**(%)**	
AEP	Senior Unsecured Notes	$ 850.0	5.63	2033
AEPTCo	Senior Unsecured Notes	700.0	5.40	2053
AEP Texas	Senior Unsecured Notes	450.0	5.40	2033
APCo	Other Long-term Debt	200.0	Variable	2024
I&M	Senior Unsecured Notes	500.0	5.63	2053
OPCo	Senior Unsecured Notes	400.0	5.00	2033
PSO	Senior Unsecured Notes	475.0	5.25	2033
SWEPCo	Senior Unsecured Notes	350.0	5.30	2033
Non-Registrant:				
KPCo	Pollution Control Bonds	65.0	4.70	2026
Transource Energy	Other Long-term Debt	13.0	Variable	2025
Total Issuances		$ 4,003.0		

(a) Amounts indicated on the statements of cash flows are net of issuance costs and premium or discount and will not tie to the issuance amounts.

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		**(in millions)**	**(%)**	
AEP Texas	Senior Unsecured Notes	$ 125.0	3.09	2023
AEP Texas	Securitization Bonds	31.5	2.85	2024
AEP Texas	Securitization Bonds	11.7	2.06	2025
APCo	Securitization Bonds	9.7	2.01	2023
APCo	Securitization Bonds	3.3	3.77	2028
I&M	Senior Unsecured Notes	250.0	3.20	2023
I&M	Notes Payable	1.2	Variable	2023
I&M	Notes Payable	2.4	Variable	2024
I&M	Notes Payable	9.2	Variable	2025
I&M	Notes Payable	7.9	0.93	2025
I&M	Notes Payable	13.7	3.44	2026
I&M	Notes Payable	13.6	5.93	2027
I&M	Other Long-term Debt	1.2	6.00	2025
OPCo	Other Long-term Debt	0.6	1.15	2028
PSO	Other Long-term Debt	0.3	3.00	2027
SWEPCo	Notes Payable	25.0	6.37	2024
SWEPCo	Notes Payable	30.9	4.58	2032
SWEPCo	Other Long-term Debt	38.2	4.68	2028
Non-Registrant:				
KPCo	Pollution Control Bonds	65.0	2.35	2023
Transource Energy	Senior Unsecured Notes	1.3	2.75	2050
Total Retirements and Principal Payments		$ 641.7		

Long-term Debt Subsequent Event

In July 2023, I&M retired $8 million of Notes Payable related to DCC Fuel.

Equity Units (Applies to AEP)

2020 Equity Units

In August 2020, AEP issued 17 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $850 million. Net proceeds from the issuance were approximately $833 million. The proceeds were used to support AEP's overall capital expenditure plans.

Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 1.30% Junior Subordinated Notes due in 2025 and a forward equity purchase contract which settles after three years in August 2023. In June 2023, AEP successfully remarketed the Junior Subordinated Notes on behalf of holders of the corporate units. AEP did not receive any proceeds from the remarketing which were used to purchase a portfolio of treasury securities maturing on August 14, 2023. On August 15, 2023, the proceeds from the maturing treasury portfolio, currently held by the collateral agent, will be used to settle the forward equity purchase contract entered into as part of the Equity Units transaction. The interest rate on the Junior Subordinated Notes was reset to 5.699% with the maturity remaining in 2025.

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.

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).

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 0.6% of consolidated tangible net assets as of June 30, 2023. 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 June 30, 2023 and December 31, 2022 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 six months ended June 30, 2023 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 June 30, 2023	Authorized Short-term Borrowing Limit	
				(in millions)				
AEP Texas	$ 477.5		$ —	$ 279.9	$ —	$ (135.9)	$ 500.0	
AEPTCo	471.3		309.4	153.1	85.9	26.9	820.0	(a)
APCo	388.6		19.8	295.0	18.9	(247.2)	500.0	
I&M	475.3		100.3	174.0	43.0	40.5	500.0	
OPCo	485.7		64.7	266.4	40.2	(72.3)	500.0	
PSO	375.0		121.5	127.5	74.8	(68.1)	400.0	
SWEPCo	401.6	(b)	—	220.6	—	(32.6)	400.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.
(b) SWEPCo's maximum borrowings from the Utility Money Pool exceeded the authorized short-term borrowing limit by $1.6 million on March 15, 2023. On March 16, 2023, SWEPCo's borrowings from the Utility Money Pool were reduced below the $400 million authorized limit and borrowings have continued to remain below the authorized limit.

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 June 30, 2023 and December 31, 2022 are included in Advances to Affiliates on the subsidiaries' balance sheets. The Nonutility Money Pool participants' activity for the six months ended June 30, 2023 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 June 30, 2023
		(in millions)	
AEP Texas	$ 6.9	$ 6.8	$ 6.9
SWEPCo	2.2	2.1	2.2

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 June 30, 2023 and December 31, 2022 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 six months ended June 30, 2023 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 June 30, 2023	Loans to AEP as of June 30, 2023	Authorized Short-term Borrowing Limit
(in millions)						
$ 29.4	$ 158.1	$ 2.9	$ 70.2	$ 21.9	$ —	$ 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:

	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
Maximum Interest Rate	5.69 %	2.11 %
Minimum Interest Rate	4.66 %	0.10 %

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 Six Months Ended June 30, 2023	2022	Average Interest Rate for Funds Loaned to the Utility Money Pool for Six Months Ended June 30, 2023	2022
AEP Texas	5.35 %	0.90 %	— %	1.48 %
AEPTCo	5.16 %	0.93 %	5.46 %	1.49 %
APCo	5.36 %	1.08 %	5.35 %	0.95 %
I&M	5.13 %	0.92 %	5.42 %	0.96 %
OPCo	5.30 %	0.83 %	5.60 %	1.20 %
PSO	5.47 %	1.17 %	5.11 %	0.65 %
SWEPCo	5.22 %	1.25 %	— %	0.55 %

Maximum, minimum and average interest rates for funds loaned to the Nonutility Money Pool are summarized in the following table:

	Six Months Ended June 30, 2023			Six Months Ended June 30, 2022		
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	5.69 %	4.66 %	5.35 %	2.11 %	0.46 %	0.98 %
SWEPCo	5.69 %	4.66 %	5.35 %	2.11 %	0.46 %	0.98 %

AEPTCo's maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following table:

Six Months Ended June 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
2023	5.69 %	4.53 %	5.69 %	4.53 %	5.27 %	5.35 %
2022	2.11 %	0.46 %	2.11 %	0.46 %	1.02 %	0.89 %

Short-term Debt (Applies to AEP and SWEPCo)

Outstanding short-term debt was as follows:

		June 30, 2023		December 31, 2022	
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	5.45 %	$ 750.0	4.67 %
AEP	Commercial Paper	2,238.7	5.50 %	2,862.2	4.80 %
AEP	Term Loan	500.0	6.08 %	—	— %
AEP	Term Loan	150.0	5.94 %	150.0	5.17 %
AEP	Term Loan	125.0	5.94 %	125.0	5.17 %
AEP	Term Loan	100.0	5.94 %	100.0	5.23 %
AEP	Term Loan	—	— %	125.0	4.87 %
SWEPCo	Notes Payable	3.9	7.53 %	—	— %
AEP	**Total Short-term Debt**	$ 3,867.6		$ 4,112.2	

(a) Weighted-average rate as of June 30, 2023 and December 31, 2022, respectively.
(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 includes a $125 million and a $625 million facility, both of which expire in September 2024. As of June 30, 2023, the affiliated utility subsidiaries were in compliance with all requirements under the agreement.

Accounts receivable information for AEP Credit was as follows:

	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	5.25 %	0.91 %	5.06 %	0.61 %
Net Uncollectible Accounts Receivable Written-Off	$ 7.3	$ 6.2	$ 14.1	$ 13.6

	June 30, 2023	December 31, 2022
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,184.9	$ 1,167.7
Short-term – Securitized Debt of Receivables	750.0	750.0
Delinquent Securitized Accounts Receivable	49.4	44.2
Bad Debt Reserves Related to Securitization	41.7	39.7
Unbilled Receivables Related to Securitization	392.4	360.9

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 expected 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	June 30, 2023	December 31, 2022
	(in millions)	
APCo	$ 181.9	$ 194.4
I&M	177.3	166.9
OPCo	477.4	478.6
PSO	177.8	155.5
SWEPCo	191.6	194.0

The fees paid to AEP Credit for customer accounts receivable sold were:

Company	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(in millions)			
APCo	$ 4.3	$ 1.5	$ 9.2	$ 2.8
I&M	3.9	2.0	7.8	3.7
OPCo	7.6	7.5	14.9	14.9
PSO	3.5	1.3	6.7	2.2
SWEPCo	4.4	1.5	8.7	2.8

The proceeds on the sale of receivables to AEP Credit were:

Company	Three Months Ended June 30, 2023	Three Months Ended June 30, 2022	Six Months Ended June 30, 2023	Six Months Ended June 30, 2022
	(in millions)			
APCo	$ 414.9	$ 339.0	$ 921.1	$ 754.5
I&M	497.2	502.4	1,022.6	1,015.8
OPCo	783.9	693.3	1,668.3	1,409.9
PSO	460.2	428.5	876.5	791.9
SWEPCo	460.5	437.2	898.1	831.7

13. VARIABLE INTEREST ENTITIES

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

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether AEP is the primary beneficiary of a VIE, management considers whether AEP has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE.

AEP holds ownership interests in businesses with varying ownership structures. AEP has not provided material financial or other support that was not previously contractually required to any of its consolidated VIEs. If an entity is determined not to be a VIE, or if the entity is determined to be a VIE and AEP is not deemed to be the primary beneficiary, the entity is accounted for under the equity method of accounting.

Consolidated Variable Interests Entities

The Annual Report on Form 10-K for the year ended December 31, 2022includes a detailed discussion of the Registrants' consolidated VIEs. There were no reconsideration events with respect to those VIEs in the second quarter of 2023.

The balances below represent the assets and liabilities of consolidated VIEs. These balances include intercompany transactions that are eliminated upon consolidation.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
June 30, 2023

	Registrant Subsidiaries				
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding
			(in millions)		
ASSETS					
Current Assets	$ 5.8	$ 72.5	$ 26.9	$ 25.4	$ 13.3
Net Property, Plant and Equipment	—	129.3	—	—	—
Other Noncurrent Assets	129.7	63.6	109.5 (a)	157.2 (b)	151.8 (c)
Total Assets	$ 135.5	$ 265.4	$ 136.4	$ 182.6	$ 165.1
LIABILITIES AND EQUITY					
Current Liabilities	$ 19.8	$ 72.4	$ 74.5	$ 36.7	$ 29.6
Noncurrent Liabilities	115.6	193.0	57.5	144.7	133.6
Equity	0.1	—	4.4	1.2	1.9
Total Liabilities and Equity	$ 135.5	$ 265.4	$ 136.4	$ 182.6	$ 165.1

(a) Includes an intercompany item eliminated in consolidation of $12 million.
(b) Includes an intercompany item eliminated in consolidation of $7 million.
(c) Includes an intercompany item eliminated in consolidation of $2 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
June 30, 2023

	Other Consolidated VIEs		
	AEP Credit	Protected Cell of EIS	Transource Energy
		(in millions)	
ASSETS			
Current Assets	$ 1,186.0	$ 195.1	$ 29.3
Net Property, Plant and Equipment	—	—	496.6
Other Noncurrent Assets	9.4	—	5.3
Total Assets	$ 1,195.4	$ 195.1	$ 531.2
LIABILITIES AND EQUITY			
Current Liabilities	$ 1,132.8	$ 39.7	$ 21.1
Noncurrent Liabilities	0.9	81.9	232.0
Equity	61.7	73.5	278.1
Total Liabilities and Equity	$ 1,195.4	$ 195.1	$ 531.2

Apple Blossom, Black Oak, Santa Rita East and Dry Lake are consolidated VIEs included in the plan of sale of the Competitive Contracted Renewables Portfolio. See the "Planned Disposition of the Competitive Contracted Renewables Portfolio" section of Note 6 for the assets and liabilities classified Held for Sale as of June 30, 2023 inclusive of the assets and liabilities of the aforementioned consolidated VIEs.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2022

	Registrant Subsidiaries				
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding
			(in millions)		
ASSETS					
Current Assets	$ 108.3	$ 90.2	$ 27.0	$ 21.1	$ 13.5
Net Property, Plant and Equipment	7.2	179.1	—	—	—
Other Noncurrent Assets	130.0	94.0	140.9 (a)	168.8 (b)	164.6 (c)
Total Assets	$ 245.5	$ 363.3	$ 167.9	$ 189.9	$ 178.1
LIABILITIES AND EQUITY					
Current Liabilities	$ 25.4	$ 90.0	$ 73.2	$ 31.3	$ 29.3
Noncurrent Liabilities	219.4	273.3	90.4	157.4	146.9
Equity	0.7	—	4.3	1.2	1.9
Total Liabilities and Equity	$ 245.5	$ 363.3	$ 167.9	$ 189.9	$ 178.1

(a) Includes an intercompany item eliminated in consolidation of $16 million.
(b) Includes an intercompany item eliminated in consolidation of $7 million.
(c) Includes an intercompany item eliminated in consolidation of $2 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2022

	Other Consolidated VIEs					
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**	**Apple Blossom and Black Oak**	**Santa Rita East**	**Dry Lake**
	(in millions)					
ASSETS						
Current Assets	$ 1,181.0	$ 194.5	$ 23.5	$ 8.3	$ 21.3	$ 4.0
Net Property, Plant and Equipment	—	—	482.3	216.5	421.6	142.6
Other Noncurrent Assets	9.0	0.3	2.7	13.6	0.1	0.3
Total Assets	$ 1,190.0	$ 194.8	$ 508.5	$ 238.4	$ 443.0	$ 146.9
LIABILITIES AND EQUITY						
Current Liabilities	$ 1,087.8	$ 46.4	$ 22.8	$ 4.5	$ 9.6	$ 1.0
Noncurrent Liabilities	0.9	79.1	218.6	5.4	7.3	0.7
Equity	101.3	69.3	267.1	228.5	426.1	145.2
Total Liabilities and Equity	$ 1,190.0	$ 194.8	$ 508.5	$ 238.4	$ 443.0	$ 146.9

Significant Variable Interests in Non-Consolidated VIEs and Significant Equity Method Investments

The Annual Report on Form 10-K for the year ended December 31, 2022 includes a detailed discussion of significant variable interests in non-consolidated VIEs and other significant equity method investments. There were no reconsideration events or material changes in carrying values as of June 30, 2023.

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 June 30, 2023						
	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	$ 962.0	$ 574.1	$ —	$ —	$ —	$ —	$ 1,536.1
Commercial Revenues	642.7	358.3	—	—	—	—	1,001.0
Industrial Revenues	698.9	152.1	—	—	—	(0.1)	850.9
Other Retail Revenues	58.9	12.3	—	—	—	—	71.2
Total Retail Revenues	2,362.5	1,096.8	—	—	—	(0.1)	3,459.2
Wholesale and Competitive Retail Revenues:							
Generation Revenues	141.4	—	—	19.6	—	0.1	161.1
Transmission Revenues (a)	113.5	184.1	455.8	—	—	(402.8)	350.6
Renewable Generation Revenues (b)	—	—	—	33.1	—	(3.1)	30.0
Retail, Trading and Marketing Revenues (b)	—	—	—	407.7	1.2	(10.1)	398.8
Total Wholesale and Competitive Retail Revenues	254.9	184.1	455.8	460.4	1.2	(415.9)	940.5
Other Revenues from Contracts with Customers (c)	61.9	56.1	4.3	6.2	28.6	(39.9)	117.2
Total Revenues from Contracts with Customers	2,679.3	1,337.0	460.1	466.6	29.8	(455.9)	4,516.9
Other Revenues:							
Alternative Revenue Programs (b) (d)	(4.9)	(2.9)	(1.5)	—	—	(6.3)	(15.6)
Other Revenues (b) (e)	0.1	6.1	—	(135.2)	2.2	(2.0)	(128.8)
Total Other Revenues	(4.8)	3.2	(1.5)	(135.2)	2.2	(8.3)	(144.4)
Total Revenues	$ 2,674.5	$ 1,340.2	$ 458.6	$ 331.4	$ 32.0	$ (464.2)	$ 4,372.5

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $360 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 $26 million. The remaining affiliated amounts were immaterial.
(d) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(e) Generation & Marketing includes economic hedge activity.

	Three Months Ended June 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	$ 979.3	$ 561.6	$ —	$ —	$ —	$ —	$ 1,540.9
Commercial Revenues	624.8	331.7	—	—	—	—	956.5
Industrial Revenues	641.8	162.5	—	—	—	—	804.3
Other Retail Revenues	52.9	12.8	—	—	—	—	65.7
Total Retail Revenues	2,298.8	1,068.6	—	—	—	—	3,367.4
Wholesale and Competitive Retail Revenues:							
Generation Revenues	188.3	—	—	83.0	—	0.1	271.4
Transmission Revenues (a)	108.8	164.9	421.6	—	—	(332.0)	363.3
Renewable Generation Revenues (b)	—	—	—	38.2	—	(2.9)	35.3
Retail, Trading and Marketing Revenues (b)	—	—	—	408.3	1.3	(2.3)	407.3
Total Wholesale and Competitive Retail Revenues	297.1	164.9	421.6	529.5	1.3	(337.1)	1,077.3
Other Revenues from Contracts with Customers (c)	49.2	65.9	0.2	1.6	20.9	(21.1)	116.7
Total Revenues from Contracts with Customers	2,645.1	1,299.4	421.8	531.1	22.2	(358.2)	4,561.4
Other Revenues:							
Alternative Revenue Programs (b) (d)	3.3	(4.6)	(43.0)	—	—	(13.1)	(57.4)
Other Revenues (b) (e)	0.1	6.8	—	128.5	2.3	(2.0)	135.7
Total Other Revenues	3.4	2.2	(43.0)	128.5	2.3	(15.1)	78.3
Total Revenues	$ 2,648.5	$ 1,301.6	$ 378.8	$ 659.6	$ 24.5	$ (373.3)	$ 4,639.7

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $334 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 Vertically Integrated Utilities was $5 million. The remaining affiliated amounts were immaterial.
(d) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(e) Generation & Marketing includes economic hedge activity.

	Three Months Ended June 30, 2023						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
tail Revenues:							
Residential Revenues	$ 144.9	$ —	$ 324.8	$ 185.2	$ 429.3	$ 186.5	$ 185.1
Commercial Revenues	100.6	—	163.6	141.4	257.8	131.7	153.8
Industrial Revenues	35.2	—	192.5	155.9	116.8	107.8	110.6
Other Retail Revenues	8.7	—	25.2	1.2	3.6	28.3	2.6
tal Retail Revenues	289.4	—	706.1	483.7	807.5	454.3	452.1
ıolesale Revenues:							
Generation Revenues (a)	—	—	64.2	63.5	—	4.3	43.9
Transmission Revenues (b)	163.1	444.7	43.9	9.6	21.0	9.9	38.3
tal Wholesale Revenues	163.1	444.7	108.1	73.1	21.0	14.2	82.2
Other Revenues from Contracts with Customers (c)	10.7	4.1	11.8	45.0	45.5	7.2	7.0
Total Revenues from Contracts with Customers	463.2	448.8	826.0	601.8	874.0	475.7	541.3
her Revenues:							
Alternative Revenue Programs (d) (e)	(2.0)	(3.9)	0.5	(2.6)	(0.9)	(1.0)	(3.5)
Other Revenues (e)	—	—	—	—	6.0	—	—
tal Other Revenues	(2.0)	(3.9)	0.5	(2.6)	5.1	(1.0)	(3.5)
tal Revenues	$ 461.2	$ 444.9	$ 826.5	$ 599.2	$ 879.1	$ 474.7	$ 537.8

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $38 million primarily related to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $357 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) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(e) Amounts include affiliated and nonaffiliated revenues.

		Three Months Ended June 30, 2022						
		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
tail Revenues:								
Residential Revenues	$	174.9	$ —	$ 313.2	$ 195.2	$ 386.7	$ 185.2	$ 188.6
Commercial Revenues		110.6	—	152.6	138.6	221.1	121.2	146.0
Industrial Revenues		36.6	—	161.9	160.0	126.0	92.5	97.1
Other Retail Revenues		9.5	—	20.2	1.2	3.4	25.8	4.4
tal Retail Revenues		331.6	—	647.9	495.0	737.2	424.7	436.1
holesale Revenues:								
Generation Revenues (a)		—	—	63.5	94.2	—	0.3	57.4
Transmission Revenues (b)		143.8	406.1	40.8	8.7	21.1	9.1	39.3
tal Wholesale Revenues		143.8	406.1	104.3	102.9	21.1	9.4	96.7
Other Revenues from Contracts with Customers (c)		5.6	0.2	20.6	25.8	60.2	9.6	6.0
Total Revenues from Contracts with Customers		481.0	406.3	772.8	623.7	818.5	443.7	538.8
her Revenues:								
Alternative Revenue Programs (d) (e)		(2.2)	(41.9)	0.8	7.3	(2.4)	(0.8)	(2.2)
Other Revenues (e)		—	—	—	—	6.8	—	—
tal Other Revenues		(2.2)	(41.9)	0.8	7.3	4.4	(0.8)	(2.2)
tal Revenues	$	478.8	$ 364.4	$ 773.6	$ 631.0	$ 822.9	$ 442.9	$ 536.6

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $42 million primarily related to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $330 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $19 million primarily related to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(e) Amounts include affiliated and nonaffiliated revenues.

	Six Months Ended June 30, 2023						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
tail Revenues:							
Residential Revenues	$ 2,132.4	$ 1,230.9	$ —	$ —	$ —	$ —	$ 3,363.3
Commercial Revenues	1,276.1	734.2	—	—	—	—	2,010.3
Industrial Revenues (a)	1,369.2	365.0	—	—	—	(0.3)	1,733.9
Other Retail Revenues	115.7	24.4	—	—	—	—	140.1
al Retail Revenues	4,893.4	2,354.5	—	—	—	(0.3)	7,247.6
Wholesale and Competitive Retail Revenues:							
Generation Revenues	324.2	—	—	52.0	—	0.1	376.3
Transmission Revenues (b)	228.2	348.3	905.9	—	—	(804.6)	677.8
Renewable Generation Revenues (a)	—	—	—	54.4	—	(3.2)	51.2
Retail, Trading and Marketing Revenues (c)	—	—	—	821.4	0.9	(10.0)	812.3
Total Wholesale and Competitive Retail Revenues	552.4	348.3	905.9	927.8	0.9	(817.7)	1,917.6
Other Revenues from Contracts with Customers (d)	94.5	98.9	7.9	6.8	58.0	(83.6)	182.5
Total Revenues from Contracts with Customers	5,540.3	2,801.7	913.8	934.6	58.9	(901.6)	9,347.7
her Revenues:							
Alternative Revenue Programs (a) (e)	(8.0)	(14.5)	0.3	—	—	(3.4)	(25.6)
Other Revenues (a) (f)	—	17.2	—	(276.2)	3.2	(2.9)	(258.7)
al Other Revenues	(8.0)	2.7	0.3	(276.2)	3.2	(6.3)	(284.3)
al Revenues	$ 5,532.3	$ 2,804.4	$ 914.1	$ 658.4	$ 62.1	$ (907.9)	$ 9,063.4

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $712 million. The affiliated revenue for Vertically Integrated Utilities was $80 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $10 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $55 million. The remaining affiliated amounts were immaterial.
(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(f) Generation & Marketing includes economic hedge activity.

	Six Months Ended June 30, 2022						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
tail Revenues:							
Residential Revenues	$ 2,130.1	$ 1,162.2	$ —	$ —	$ —	$ —	$ 3,292.3
Commercial Revenues	1,197.7	621.4	—	—	—	—	1,819.1
Industrial Revenues	1,204.8	295.8	—	—	—	(0.4)	1,500.2
Other Retail Revenues	100.3	24.4	—	—	—	—	124.7
tal Retail Revenues	4,632.9	2,103.8	—	—	—	(0.4)	6,736.3
Wholesale and Competitive Retail Revenues:							
Generation Revenues	375.5	—	—	123.3	—	0.1	498.9
Transmission Revenues (a)	214.1	319.8	836.1	—	—	(693.8)	676.2
Renewable Generation Revenues (b)	—	—	—	60.6	—	(3.7)	56.9
Retail, Trading and Marketing Revenues (c)	—	—	—	797.1	4.5	(11.3)	790.3
Total Wholesale and Competitive Retail Revenues	589.6	319.8	836.1	981.0	4.5	(708.7)	2,022.3
Other Revenues from Contracts with Customers (d)	110.8	119.7	—	10.2	34.8	(39.7)	235.8
Total Revenues from Contracts with Customers	5,333.3	2,543.3	836.1	991.2	39.3	(748.8)	8,994.4
her Revenues:							
Alternative Revenue Programs (b) (e)	2.5	(8.0)	(45.9)	—	—	(11.8)	(63.2)
Other Revenues (b) (f)	0.1	13.1	—	287.7	5.1	(4.9)	301.1
tal Other Revenues	2.6	5.1	(45.9)	287.7	5.1	(16.7)	237.9
tal Revenues	$ 5,335.9	$ 2,548.4	$ 790.2	$ 1,278.9	$ 44.4	$ (765.5)	$ 9,232.3

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $661 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 $19 million. The remaining affiliated amounts were immaterial.
(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(f) Generation & Marketing includes economic hedge activity.

	Six Months Ended June 30, 2023						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
tail Revenues:							
Residential Revenues	$ 275.6	$ —	$ 795.3	$ 424.8	$ 955.3	$ 357.4	$ 361.0
Commercial Revenues	197.9	—	334.9	280.3	536.3	240.8	297.3
Industrial Revenues (a)	74.5	—	378.3	308.5	290.4	206.1	214.8
Other Retail Revenues	17.0	—	51.4	2.5	7.4	52.5	5.2
tal Retail Revenues	565.0	—	1,559.9	1,016.1	1,789.4	856.8	878.3
ıolesale Revenues:							
Generation Revenues (b)	—	—	144.4	167.5	—	5.2	83.5
Transmission Revenues (c)	309.4	883.4	85.3	17.7	38.9	21.2	81.2
tal Wholesale Revenues	309.4	883.4	229.7	185.2	38.9	26.4	164.7
Other Revenues from Contracts with Customers (d)	20.4	7.8	24.8	66.4	78.7	9.5	14.9
Total Revenues from Contracts with Customers	894.8	891.2	1,814.4	1,267.7	1,907.0	892.7	1,057.9
her Revenues:							
Alternative Revenue Program (a) (e)	(4.1)	(4.7)	(0.2)	(5.5)	(10.4)	(1.0)	(4.2)
Other Revenues (a)	—	—	—	—	17.1	—	—
tal Other Revenues	(4.1)	(4.7)	(0.2)	(5.5)	6.7	(1.0)	(4.2)
tal Revenues	$ 890.7	$ 886.5	$ 1,814.2	$ 1,262.2	$ 1,913.7	$ 891.7	$ 1,053.7

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $85 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $706 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $35 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

	Six Months Ended June 30, 2022						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 316.8	$ —	$ 771.2	$ 427.0	$ 845.4	$ 351.1	$ 364.5
Commercial Revenues	205.5	—	306.5	265.2	415.8	218.7	276.5
Industrial Revenues	67.2	—	315.7	296.5	228.7	171.1	181.8
Other Retail Revenues	17.7	—	40.8	2.5	6.7	47.0	6.8
Total Retail Revenues	607.2	—	1,434.2	991.2	1,496.6	787.9	829.6
Wholesale Revenues:							
Generation Revenues (a)	—	—	119.7	184.6	—	9.8	118.6
Transmission Revenues (b)	276.9	806.4	81.9	17.5	42.9	18.7	74.5
Total Wholesale Revenues	276.9	806.4	201.6	202.1	42.9	28.5	193.1
Other Revenues from Contracts with Customers (c)	14.9	(0.1)	44.9	55.7	104.8	15.0	11.3
Total Revenues from Contracts with Customers	899.0	806.3	1,680.7	1,249.0	1,644.3	831.4	1,034.0
Other Revenues:							
Alternative Revenue Program (d) (e)	(3.5)	(41.5)	0.1	7.3	(4.5)	(0.9)	(2.6)
Other Revenues (e)	—	—	0.1	(0.1)	13.1	—	—
Total Other Revenues	(3.5)	(41.5)	0.2	7.2	8.6	(0.9)	(2.6)
Total Revenues	$ 895.5	$ 764.8	$ 1,680.9	$ 1,256.2	$ 1,652.9	$ 830.5	$ 1,031.4

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $78 million primarily relating to the PPA with KGPCo.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $653 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $29 million primarily relating to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.
(e) Amounts include affiliated and nonaffiliated revenues.

Fixed Performance Obligations (Applies to AEP, APCo and I&M)

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of June 30, 2023. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market.The Registrants elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The Registrant Subsidiaries amounts shown in the table below include affiliated and nonaffiliated revenues.

Company	2023	2024-2025	2026-2027	After 2027	Total
			(in millions)		
AEP	$ 43.6	$ 161.4	$ 137.1	$ 60.9	$ 403.0
APCo	8.1	32.2	25.4	11.6	77.3
I&M	2.2	8.8	8.8	4.5	24.3

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have material contract assets as of June 30, 2023 and December 31, 2022.

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 June 30, 2023 and December 31, 2022.

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 June 30, 2023 and December 31, 2022. 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	June 30, 2023	December 31, 2022
	(in millions)	
AEP Texas	$ —	$ 0.1
AEPTCo	123.1	113.8
APCo	68.1	64.5
I&M	47.3	75.3
OPCo	68.6	49.9
PSO	30.6	18.8
SWEPCo	42.4	19.1

CONTROLS AND PROCEDURES

During the second quarter of 2023, 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 June 30, 2023, 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 second quarter of 2023 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, 2022 includes a detailed discussion of risk factors.As of June 30, 2023, the risk factors appearing in AEP's 2022 Annual Report are supplemented and updated as follows:

Our financial position may be adversely impacted if announced dispositions do not occur as planned or if assets under strategic evaluation lose value. (Applies to AEP)

In February 2022, AEP announced the initiation of a process to sell all or a portion of AEP Renewables' competitive contracted renewables portfolio within the Generation & Marketing segment. In February 2023, AEP's Board of Directors approved management's plan to sell the competitive contracted renewables portfolio and AEP signed an agreement to sell the competitive contracted renewables portfolio to a nonaffiliated party for $1.5 billion including the assumption of project debt.

In October 2022, AEP initiated a strategic evaluation for its ownership in AEP Energy.In April 2023, management completed the strategic evaluation of AEP Energy and initiated a sale process. In April 2023, AEP also made a decision to include AEP Onsite Partners in the sale process.AEP Onsite Partners also owns a 50% interest in NM Renewable Development, LLC, (NMRD)Separate from the remainder of AEP Onsite Partners, AEP and the joint owner have agreed to initiate a joint sales process for their respective interests in NMRD.

In July 2023, AEP made a decision to initiate a sales process for its investment in Pioneer Transmission, LLC and Prairie Wind Transmission, LLC.

Any planned sale of assets and investments, including subsidiaries, may not occur for any number of reasons beyond our control, including regulatory approval on terms that are acceptable. Depending on the outcome of these potential sales, it could reduce future net income 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 June 30, 2023.

Item 5. Other Information

During the three months ended June 30, 2023, none of the Company's directors or officers (as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934) adopted, terminated or modified a Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement (as such terms are defined in Item 408 of Regulation S-K of the Securities Act of 1933).

Item 6. Exhibits

The documents designated with an (*) below have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof.

Exhibit	Description	Previously Filed as Exhibit to:
AEP‡ File No. 1-3525		
4(c)	Supplemental Indenture No. 5 between AEP and The Bank of New York Mellon Trust Company, N.A. as Trustee dated June 2, 2023 establishing terms of the Remarketed Junior Subordinated Debentures due 2025.	Form 8-K dated June 2, 2023 Exhibit 4(a)
AEP TEXAS‡ File No. 333-221643		
4(b)	Company Order and Officer's Certificate between AEP Texas Inc. and The Bank of New York Mellon Trust Company, N.A. as Trustee dated May 24, 2023 establishing terms of the 5.40% Senior Notes, Series M, due 2033.	Form 8-K dated May 24, 2023 Exhibit 4(a)
OPCo‡ File No. 1-6543		
4(a)	Company Order and Officer's Certificate between Ohio Power Company and The Bank of New York Mellon Trust Company, N.A. as Trustee dated May 10, 2023 establishing terms of the 5.00% Senior Notes, Series S, due 2033.	Form 8-K dated May 10, 2023 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	Mutual Termination Agreement dated and effective April 17, 2023 among AEP, AEP Transmission Company and Liberty Utilities Co. terminating the Stock Purchase Agreement dated October 26, 2021 the First Amendment to the Stock Purchase Agreement, dated as of September 29, 2022, and the Second Amendment to the Stock Purchase Agreement, dated as of January 16, 2023.	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

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
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/ Kate Sturgess
Kate Sturgess
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/ Kate Sturgess
Kate Sturgess
Controller and Chief Accounting Officer

Date: July 27, 2023