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

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **September 30, 2024**
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

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 November 6, 2024
American Electric Power Company, Inc.	532,565,335
	($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
September 30, 2024

Part II. OTHER INFORMATION

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

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP 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 counterparties.
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.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
ATM	At-the-Market.
CAA	Clean Air Act.
CAMT	Corporate Alternative Minimum Tax.
CCR	Coal Combustion Residual.
CO_2	Carbon dioxide and other greenhouse gases.
CODM	Chief Operating Decision Maker.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,296 MW nuclear plant owned by I&M.
CSAPR	Cross-State Air Pollution Rule.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel XV, DCC Fuel XVI, DCC Fuel XVII, DCC Fuel XVIII, DCC Fuel XIX and DCC Fuel XX consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo. DHLC is a non-consolidated VIE of SWEPCo.
DIR	Distribution Investment Rider.

Term	Meaning
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.
ETR	Effective Tax Rate.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
GHG	Greenhouse gas.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRA	On August 16, 2022, President Biden signed into law legislation commonly referred to as the "Inflation Reduction Act" (IRA).
IRP	Integrated Resource Plan.
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.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
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.

Term	Meaning
NAAQS	National Ambient Air Quality Standards.
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.
NMRD	New Mexico Renewable Development, LLC.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NOLC	Net Operating Loss Carryforward.
NO_x	Nitrogen Oxide.
OCC	Corporation Commission of the State of Oklahoma.
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.
PFD	Proposal for Decision.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PLR	Private Letter Ruling.
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.
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.
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.
SSO	Standard service offer.

Term	Meaning
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
Transition Funding	AEP Texas Central Transition Funding III LLC, a wholly-owned subsidiary of AEP Texas and consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to restructuring legislation in Texas.
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.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
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 economic impact of increased global conflicts and trade tensions, and the adoption or expansion of economic sanctions, tariffs or trade restrictions.
- Inflationary or deflationary interest rate trends.
- Volatility and disruptions in financial markets precipitated by any cause, including turmoil related to 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 (a) if expected sources of capital such as proceeds from the sale of assets, subsidiaries and tax credits and anticipated securitizations do not materialize or do not materialize at the level anticipated, and (b) during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Shifting demand for electricity.
- The impact of extreme weather conditions, natural disasters and catastrophic events such as storms, drought conditions and wildfires that pose significant risks including potential litigation and the inability to recover significant damages and restoration costs incurred.
- 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 parties who supply and transport fuel and the cost of storing and disposing of used fuel, including coal ash and SNF.
- The availability of fuel and necessary generation capacity and the performance of generation plants.
- The ability to recover fuel and other energy costs through regulated or competitive electric rates.
- The ability to build or acquire generation (including from renewable sources), transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) to meet the demand for electricity at acceptable prices and terms, including favorable tax treatment, cost caps imposed by regulators and other operational commitments to regulatory commissions and customers for generation projects, and to recover all related costs.
- The 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 caused by pandemics, natural disasters or other events.
- 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 by-products 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 efficiently manage 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 evolving expectations related to 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, cybersecurity threats, labor strikes impacting material supply chains, global information technology disruptions 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 2023 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.

PART I. FINANCIAL INFORMATION

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

Third Quarter of 2024 Compared to Third Quarter of 2023

Earnings Attributable to AEP Common Shareholders remained consistent, slightly increasing from $954 million in 2023 to $960 million in 2024.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

Earnings Attributable to AEP Common Shareholders increased from $1,872 million in 2023 to $2,303 million in 2024 primarily due to:

- A favorable impact from the receipt of PLRs in 2024 related to the treatment of NOLCs in retail rate making. See "NOLCs in Retail Jurisdictions - IRS PLRs" section below for additional information.
- Favorable rate proceedings in AEP's various jurisdictions.
- An increase in sales volumes driven by favorable weather and increased load in the commercial customer class.
- Investment in transmission assets, which resulted in higher revenues and income.
- A loss on the sale of the competitive contracted renewables portfolio in 2023.

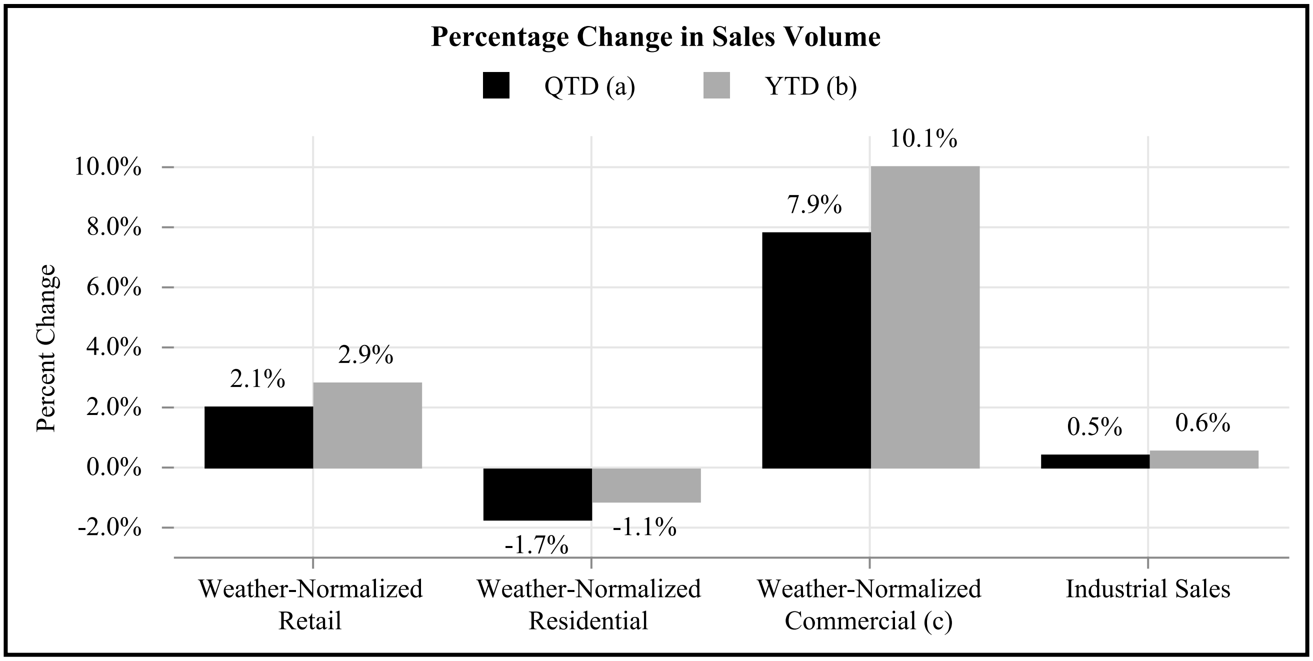
These increases were partially offset by:

- A revenue refund provision related to SWEPCo's 2012 Texas Base Rate Case and the Turk Plant.
- An increase in operating expenses due to the Federal EPA's revised CCR rule finalized in May 2024.
- A severance accrual resulting from the voluntary severance program announced in April 2024.

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

Customer Demand

AEP uses sales volumes by customer class as a way to measure significant drivers of customer demand. The percentage change in sales volumes by customer class are shown in the table below:



(a) Percentage change for the three months ended September 30, 2024 as compared to the three months ended September 30, 2023.
(b) Percentage change for the nine months ended September 30, 2024 as compared to the nine months ended September 30, 2023.
(c) The increase in commercial sales was primarily due to new data processor loads and economic development.

2024 SIGNIFICANT DEVELOPMENTS AND TRANSACTIONS

CCR Rule Revisions

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land. In the second quarter of 2024, AEP evaluated the applicability of the rule to current and former plant sites and recorded a $674 million increase in ARO. See “CCR Rule” section in Environmental Issues below for additional information.

Voluntary Severance Program

In April 2024, management announced a voluntary severance program designed to achieve a reduction in the size of AEP’s workforce. Approximately 7,400 of AEP’s 16,800 employees were eligible to participate in the program. Approximately 1,000 employees chose to take the voluntary severance package and substantially all terminated employment in July 2024. The severance program provides two weeks of base pay for every year of service with a minimum of four weeks and a maximum of 52 weeks of base pay. Certain positions impacted by the voluntary severance program have been and will continue to be refilled to maintain safe, effective and efficient operations. Net savings from the program will help offset increasing operating expenses and high interest costs in order to keep electricity costs affordable for customers. AEP recorded a $122 million pretax expense in the second quarter of 2024 related to this voluntary severance program. The Registrants paid $111 million of the severance benefits in the third quarter of 2024. See Note 13 - Voluntary Severance Program for additional information.

NOLCs in Retail Jurisdictions - IRS PLRs

The Registrants have made rate filings with state commissions to transition to stand-alone treatment of NOLCs in retail rate making. The Registrants completed the transition in Tennessee, West Virginia and Virginia prior to 2024 and in Michigan in July 2024. In the most recent KPCo, I&M (Indiana jurisdiction), PSO and SWEPCo base rate cases, the companies filed to transition to stand-alone rate making which was contingent upon a supportive PLR from the IRS.

In April 2024, supportive PLRs for certain retail jurisdictions were received from the IRS, effective March 2024. The PLRs concluded NOLCs on a stand-alone rate making basis should be included in rate base and should also be included in the computation of Excess ADIT regulatory liabilities to be refunded to customers. Based on this conclusion, I&M, PSO and SWEPCo recognized regulatory assets related to revenue requirement amounts to be collected from customers, reduced Excess ADIT regulatory liabilities and recorded favorable impacts to net income in the first quarter of 2024 as shown in the table below:

Company	Increase in Pretax Income from the Recognition of Regulatory Assets	Reduction in Income Tax Expense (a)	Increase in Net Income
		(in millions)	
I&M	$ 20.2	$ 49.5	$ 69.7
PSO	12.1	44.7	56.8
SWEPCo	35.4	101.1	136.5
AEP Total	$ 67.7	$ 195.3	$ 263.0

(a) Primarily relates to a $224 million remeasurement of Excess ADIT Regulatory Liabilities partially offset by $29 million of tax expense on favorable pretax income from the recognition of regulatory assets.

In the second quarter of 2024, requests seeking to establish a recovery mechanism for these regulatory assets were filed in Indiana, Oklahoma and Texas. In Indiana and Oklahoma, certain intervenors have challenged the recovery, or have proposed ratemaking treatment that would offset the recovery, of the regulatory assets. In the third quarter of 2024, PUCT Staff and certain intervenors in Texas requested a hearing and direct testimony was filed by SWEPCo in October 2024.

Disposition of AEP OnSite Partners

In April 2023, AEP initiated a sales process for its ownership in AEP OnSite Partners. 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. In May 2024, AEP signed an agreement to sell AEP OnSite Partners to a nonaffiliated third-party. In September 2024, AEP completed the sale to a nonaffiliated third-party and received cash proceeds of approximately $318 million, net of taxes and transaction costs. The proceeds were used to pay down short-term debt. See the "Disposition of AEP OnSite Partners" section of Note 6 for additional information.

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. Most notably this budget reconciliation legislation created a 15% minimum tax on adjusted financial statement income (CAMT), extended and increased the value of PTCs and ITCs, added a nuclear and clean hydrogen PTC, an energy storage ITC and allowed 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 September 2024, Treasury and the IRS issued proposed regulations on the application of CAMT. AEP and subsidiaries are subject to the CAMT and are expected to incur a liability in 2024. However, any CAMT cash taxes incurred 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 are presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. AEP presents the loss on sale of tax credits through income tax expense.

In April 2024, the IRS issued final regulations related to the transfer of tax credits. In 2023, AEP, on behalf of PSO, SWEPCo and AEP Energy Supply LLC, entered into transferability agreements with nonaffiliated parties to sell 2023 generated PTCs resulting in cash proceeds of approximately $174 million with $102 million received in 2023, $62 million received in the first quarter of 2024 and the remaining $10 million was received in the second quarter of 2024. In the third quarter of 2024, AEP, on behalf of PSO, SWEPCo and APCo, entered into transferability agreements with nonaffiliated parties to sell 2024 generated PTCs which will result in approximately $137 million of cash proceeds, of which approximately $91 million was received in the third quarter of 2024 and the remaining $46 million is expected to be received in the fourth quarter of 2024 and the first quarter of 2025. AEP expects to continue to explore the ability to efficiently monetize its tax credits through third-party transferability agreements.

I&M's Cook Plant qualifies for the transferable Nuclear PTC, which is available for tax years beginning in 2024 through 2032. The Nuclear PTC is calculated based on electricity generated and sold to third-parties and is subject to a "reduction amount" as the facility's gross receipts increase above a certain threshold. In the third quarter of 2024, AEP and I&M have included $64 million of estimated Nuclear PTCs within their annualized ETR. Absent specific IRS guidance, AEP and I&M's estimated 2024 Nuclear PTC was calculated using estimated 2024 gross receipts and forecasted annual generation for the Cook Plant. If, and when, IRS guidance is eventually issued, the value of the estimated Nuclear PTC will be updated to reflect such guidance, if necessary. See Note 11 - Income Taxes for additional information.

New Generation to Support Reliability

The growth of AEP's regulated generation portfolio reflects the company's commitment to meet customer's energy and capacity needs while balancing cost and reliability.

Significant Approved Generation Filings

AEP has received regulatory approvals from various state regulatory commissions to acquire approximately 2,505 MWs of owned renewable generation facilities, totaling approximately $6 billion. The estimated cost of these facilities are included in the Budgeted Capital Expenditures disclosure included in the Financial Condition section below. In addition, AEP has received regulatory approvals for 792 MWs of renewable purchase power agreements. The following table summarizes regulatory approvals received for active renewable projects as of September 30, 2024:

Company	Generation Type	Expected Commercial Operation	Owned/PPA	Generating Capacity
				(in MWs)
APCo	Solar	2024-2027	PPA	339
APCo (a)	Wind	2025-2026	Owned	344
I&M	Solar	2026	PPA	100
I&M	Solar	2027	Owned	469
I&M	Wind/Solar	2025-2027	PPA	280
PSO (b)	Solar	2025-2026	Owned	340
PSO (b)	Wind	2025-2026	Owned	553
SWEPCo (c)	Solar	2025	PPA	73
SWEPCo (c)	Wind	2024-2025	Owned	799
Total Approved Renewable Projects				3,297

(a) APCo issued notice to proceed for the construction of 204 MWs of wind capacity.
(b) PSO issued notices to proceed for the construction of two wind facilities and one solar facility for a combined total capacity of 477 MWs. These facilities reflect the first of the approved projects contemplated within PSO's 893 MWs of total new renewable generation.
(c) Includes approvals by the APSC and LPSC for 799 MWs of owned wind projects which have commenced construction. Additionally, the LPSC approved the flex-up option, allowing SWEPCo to provide additional services to Louisiana customers and recover the portion of the projects denied by the PUCT.

In June 2024, PSO entered into a PSA to acquire a 795 MW combined-cycle power generation facility located in Oklahoma. The acquisition is subject to OCC pre-approval including the approval of a rider to allow asset recovery prior to the inclusion in base rates in a future rate case. The acquisition also requires FERC approval and clearance under the Hart-Scott-Rodino Act. Subject to these approvals, PSO expects to close on the transaction by June 30, 2025.

In addition to the generation projects discussed above, AEP enters into Capacity Purchase Agreements (CPA) to satisfy operating companies capacity reserve margins to serve customers. The following table includes CPA amounts currently under contract, by year, for the five year period 2024-2028:

	I&M		KPCo		PSO		SWEPCo		WPCo
	Coal	Natural Gas	Coal	Natural Gas	Natural Gas	Wind	Natural Gas	Wind	Coal
Delivery Start Year	(in MWs)								
2024	230	314	74	80	1,114	29	425	57	72
2025	—	440	—	85	1,150	29	500	157	—
2026	—	—	—	—	980	86	350	100	—
2027	—	210	—	—	260	86	300	100	—
2028	—	1,050	—	—	260	—	300	—	—

Significant Generation Requests for Proposal (RFP)

The table below includes active RFPs issued for both owned and purchased power generation. Unless otherwise noted, RFPs issued are all-source solicitations for accredited capacity. Projects selected will be subject to regulatory approval.

Company	Issuance Date	Projected In-Service Dates	Generating Capacity
			(in MWs)
KPCo (a)	September 2023	2026/2027	1,300
PSO	November 2023	2027/2028	1,500
SWEPCo	January 2024	2028	2,100
APCo (b)	May 2024	2028	1,100
I&M (c)	September 2024	2029	4,000
Total Significant RFPs			10,000

(a) RFP is seeking proposals for PPAs only.
(b) RFP is seeking wind, solar, stand-alone battery energy storage systems and Renewable Energy Certificates.
(c) RFP seeks up to 4,000 MW (cumulatively) from intermittent (wind, solar), non-intermittent (dispatchable), and emerging technology resources.

Regulatory Matters - Utility Rates and Rate Proceedings

The Registrants are involved in rate cases and other proceedings 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. Depending on the outcomes, these rate cases and 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:

The following tables show the Registrants' completed and pending base rate case proceedings in 2024. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Annual Base Revenue Increase			Approved ROE	New Rates Effective
		(in millions)				
PSO	Oklahoma	$	131.0	(a)	9.3%	January 2024
APCo	Virginia		127.0	(b)	9.5%	January 2024
KPCo	Kentucky		60.0	(c)	9.75%	January 2024
I&M	Indiana		62.0	(d)	9.85%	May 2024
I&M	Michigan		17.0		9.86%	July 2024
AEP Texas	Texas		70.0		9.76%	October 2024

(a) See "2022 Oklahoma Base Rate Case" section of Note 4 in the 2023 Annual Report for additional information.
(b) See "2020-2022 Virginia Triennial Review" section of Note 4 in the 2023 Annual Report for additional information.
(c) See "2023 Kentucky Base Rate and Securitization Case" section of Note 4 in the 2023 Annual Report for additional information.
(d) A two-step increase in Indiana rates with a $28 million annual increase effective May 2024 with the remaining $34 million annual increase effective in January 2025 subject to I&M's level of electric plant in service as of December 31, 2024 in comparison to I&M's 2024 forecasted test year.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Annual Base Revenue Increase Request			Requested ROE
			(in millions)			
PSO	Oklahoma	January 2024	$	218.0	(a)	10.8%
APCo	Virginia	March 2024		64.0	(b)	10.8%
APCo	West Virginia	November 2024		250.5		10.8%

(a) In October 2024, PSO, the OCC and certain intervenors filed a joint stipulation and settlement agreement with the OCC that included a net annual revenue increase of $120 million based upon a 9.5% ROE. In October 2024, a hearing was held at the OCC and PSO implemented an interim annual base rate increase of $120 million, subject to refund pending a final order by the OCC. An order is expected in the fourth quarter of 2024.

(b) In September 2024, APCo submitted an amendment to its Virginia base case reducing the previously requested annual base rate increase from $95 million to $64 million. Alternatively, the request would be reduced to $45 million if annual environmental compliance consumable expenses are moved from base rates to recovery through APCo's environmental rate adjustment clause. An order is expected in the fourth quarter of 2024.

Other Significant Regulatory Matters

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 DIR, 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. In September 2023, OPCo and certain intervenors filed a settlement agreement with the PUCO addressing the ESP application. The settlement included a four year term from June 2024 through May 2028, an ROE of 9.7% and continuation of a number of riders including the DIR subject to revenue caps. In April 2024, the PUCO issued an order approving the settlement agreement. In May 2024, intervenors filed an application for rehearing with the PUCO on the approved settlement agreement and the PUCO denied the intervenors' application for rehearing in June 2024.

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. 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. In November 2021, SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court. 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. In October 2023, SWEPCo filed testimony with the PUCT in the remanded proceeding recommending no refund or disallowance.

In December 2023, the PUCT approved a preliminary order stating the PUCT will not address SWEPCo's request that would allow the PUCT to find cause to allow SWEPCo to exceed the Texas jurisdictional capital cost cap in the current remand proceeding. As a result of the PUCT's approval of the preliminary order, SWEPCo recorded a pretax, non-cash disallowance of $86 million in the fourth quarter of 2023.

The PUCT's December 2023 approval of the preliminary order determined that it will address, in the ongoing PUCT remand proceeding, any potential revenue refunds to customers that may be required by future PUCT orders. On March 1, 2024, SWEPCo filed supplemental direct testimony with the PUCT in response to the December 2023 preliminary order. On March 8, 2024, intervenors and the PUCT staff filed a motion with the PUCT to strike portions of SWEPCo's October 2023 direct testimony and March 2024 supplemental direct testimony. On March 19, 2024, the ALJ granted portions of the motion, which included removal of testimony supporting SWEPCo's position that refunds were not appropriate. On March 28, 2024, SWEPCo filed an appeal of the ALJ decision with the PUCT. In April 2024, intervenors and PUCT staff submitted testimony recommending customer refunds through December 2023 ranging from $149 million to $197 million, including carrying charges, with refund periods ranging from 18 months to 48 months. In May 2024, the PUCT denied SWEPCo's appeal of the ALJ's March 2024 decision. In the second quarter of 2024, based on the PUCT's decision, SWEPCo recorded a one-time, probable revenue refund provision of $160 million, including interest, associated with revenue collected from February 2013 through December 2023. In June 2024, SWEPCo and parties to the remand proceeding reached an agreement in principle that would resolve all issues in the case. In October 2024, SWEPCo filed the settlement agreement with the PUCT. Under the settlement agreement, SWEPCo will refund over a two-year period $148 million, including interest, associated with revenue collected from February 2013 through December 2023 and remove AFUDC in excess of the Texas jurisdictional capital cost cap from rate base. The settlement is expected to be considered by the PUCT in the fourth quarter of 2024.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge

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 2024, 2023, 2022 and 2021 by $52 million, $61 million, $69 million and $78 million, respectively.

In January 2024, the FERC issued two orders granting formal challenges by certain unaffiliated customers related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. Accordingly, in the third quarter of 2024, the AEP transmission owning subsidiaries within SPP provided a portion of the 2021 rate year refunds, with the remainder of the refunds expected to be provided in 2025. The AEP transmission owning subsidiaries within PJM are expected to provide their respective refunds for the 2021 rate year in 2025. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests for rehearing. In March 2024, the FERC denied AEPSC's requests for rehearing of the January 2024 orders by operation of law and stated it may address the requests for rehearing in future orders. In March 2024, AEPSC submitted refund compliance reports to the FERC, which preserve the non-finality of the FERC's January 2024 orders pending further proceedings on rehearing and appeal. In April 2024, AEPSC made filings with the FERC which request that the FERC: (a) reopen the record so that the FERC may take the IRS PLRs received in April 2024 regarding the treatment of stand-alone NOLCs in ratemaking into evidence and consider them in substantive orders on rehearing and (b) stay its January 2024 orders and related compliance filings and refunds to provide time for consideration of the April 2024 IRS PLRs. In May 2024, AEPSC filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit seeking review of the FERC's January 2024 and March 2024 decisions. In July 2024, the FERC issued orders approving AEPSC's request to reopen the record for the limited purpose of accepting into the record the IRS PLRs and establish additional briefing procedures. In August 2024, AEPSC filed briefs with the FERC requesting the commission modify or overturn their initial orders.

As a result of the January 2024 FERC orders, the Registrants' balance sheets reflect a liability for the probable refund of all NOLC revenues included in transmission formula rates for years 2024, 2023, 2022 and 2021, with interest. The Registrants have not yet been directed to make cash refunds related to the 2024, 2023 or 2022 rate years. The probable refunds to affiliated and nonaffiliated customers are reflected as Deferred Credits and Other Noncurrent Liabilities on the balance sheets, with the exception of amounts expected to be refunded within one year which are reflected in Other Current Liabilities. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Regulatory Liabilities or a reduction to Regulatory Assets on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms.

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. As of September 30, 2024, the net book value of the Turk Plant was $1.3 billion, before cost of removal including CWIP and inventory.

Approximately 20% of SWEPCo's portion 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 rates. In 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 March 2024, the APSC issued an order denying SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers. As a result of the APSC's March 2024 order, SWEPCo recorded a $32 million favorable impact to net income as a result of the reduction to the regulatory liability related to the merchant portion of Turk Plant Excess ADIT.

Kentucky Securitization Case

In January 2024, the KPSC issued a financing order approving KPCo's request to securitize certain regulatory assets balances as of the time securitization bonds are issued and concluding that costs requested for recovery through securitization were prudently incurred. The KPSC's financing order includes certain additional requirements related to securitization bond structuring, marketing, placement and issuance that were not reflected in KPCo's proposal. In accordance with Kentucky statutory requirements and the financing order, the issuance of the securitized bonds is subject to final review by the KPSC after bond pricing. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the first half of 2025, subject to market conditions. As of September 30, 2024, regulatory asset balances expected to be recovered through securitization total $485 million and include: (a) $297 million of plant retirement costs, (b) $79 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, (c) $49 million of deferred purchased power expenses, (d) $58 million of under-recovered purchased power rider costs and (e) $2 million of deferred issuance-related expenses, including KPSC advisor expenses. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Investigation of the Service, Rates and Facilities of KPCo

In June 2023, 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. In December 2023 and February 2024, KPCo and certain intervenors filed testimony with the KPSC. A hearing with the KPSC was previously scheduled to occur in June 2024. The hearing was postponed and has not yet been rescheduled. If any fines or penalties are levied against KPCo relating to the show cause order, it could reduce net income and cash flows and impact financial condition.

KPCo Fuel Adjustment Clause (FAC) Review

In December 2023, KPCo received intervenor testimony in its FAC review for the two-year period ending October 31, 2022, recommending a disallowance ranging from $44 million to $60 million of its total $432 million purchased power cost recoveries as a result of proposed modifications to the ratemaking methodology that limits purchased power costs recoverable through the FAC. A hearing was held in February 2024 and the KPSC may issue its order in the fourth quarter of 2024 or early 2025. If any fuel costs are not recoverable or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

Virginia Fuel Adjustment Clause (FAC) Review

In 2023, APCo submitted its annual fuel cost filing with the Virginia SCC. Interim Virginia FAC rates were implemented in November 2023. In APCo's 2022 Virginia fuel update filing, the Virginia staff ordered the Virginia Staff to commence an audit of APCo's fuel costs for the years ended December 31, 2019, 2020, 2021 and 2022. The Virginia staff analyzed APCo's 2019 through 2022 fuel procurement activities and concluded the procurement practices were reasonable and prudent and recommended no disallowances. In May 2024, the Virginia SCC issued an order approving the audit of APCo's 2019 and 2020 fuel costs but concluded that the review of APCo fuel costs for 2021 and 2022 remains open for further evaluation. As of September 30, 2024, APCo had a Virginia jurisdictional under-recovered fuel balance of $164 million. If any fuel costs are not recoverable or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

Ohio House Bill 6 (HB 6)

In July 2019, 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 February 2024, an Ohio grand jury indictment charged certain former FirstEnergy executives and the former PUCO Chairman and related entities with various crimes, including bribery. In 2021, four AEP shareholders filed derivative actions purporting to assert claims on behalf of AEP against certain AEP officers and directors. In April 2024, AEP reached an agreement with the four shareholders to fully and finally resolve the derivative actions, and the settlement of those actions was approved in October 2024. 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: (a) is unable to recover the costs of renewable energy contracts on a bypassable basis by the end of 2032, (b) is unable to recover costs of OVEC after 2030 or (c) incurs significant costs associated with the derivative actions, it could reduce future net income and cash flows and impact financial condition.

Hurricane Helene

In late September 2024, the remnants of Hurricane Helene significantly impacted APCo's Virginia and West Virginia service territories leading to approximately 260,000 customer outages and damages to APCo's power grid. Storm restoration efforts continued into early October and APCo completed restoration efforts for all customers who lost power by October 6th, 2024. As of September 30, 2024, APCo incurred approximately $19 million ($13 million related to the Virginia jurisdiction and $6 million related to the West Virginia jurisdiction) of incremental other operation and maintenance expenses and approximately $8 million of capital expenditures. APCo deferred $16 million of the incremental other operation and maintenance expenses as regulatory assets as the costs are deemed probable of future recovery. Based on the information currently available, APCo estimates total storm restoration costs to be approximately $140 million, of which 70% is expected to be deferred as regulatory assets and the remaining 30% of the costs are expected to be capital expenditures. If any costs related to Hurricane Helene are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Supply Chain Disruption and Inflation

The Registrants have experienced certain supply chain disruptions driven by several factors including international tensions and the ramifications of regional conflict, 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 seeking to limit the impacts of these supply chain disruptions.

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 the pace of inflation will continue to moderate. 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.

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 (collectively, the "Derivative Actions") 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 in April 2022. In June 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. In September 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. In January 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. In March 2023, the federal district court issued an order granting the motion to dismiss with prejudice and denying the New York plaintiffs' motion to intervene. In April 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.

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 letter from counsel representing the purported AEP shareholder who had 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). The Litigation Demand is directed to the AEP Board and contains factual allegations involving HB 6 that are generally consistent with those in the Derivative Actions. The Litigation Demand requested, 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 asserting claims similar to the claims asserted in the Derivative Actions. The AEP Board considered the Litigation Demand and formed a committee of the Board (the Demand Review Committee) to investigate, review, monitor and analyze the Litigation Demand and make a recommendation to the AEP Board regarding a reasonable and appropriate response to the same.

In April 2024, AEP reached an agreement with the four shareholders to fully and finally resolve the Derivative Actions and the Litigation Demand, and all claims asserted or that could have been asserted by any AEP shareholder based on the facts alleged, in the manner and upon the terms and conditions set forth in the settlement documents (the Settlement). In July 2024, the U.S. District Court preliminarily approved the Settlement. The Settlement includes a payment of $450 thousand for attorneys' fees and the implementation of certain governance changes outlined in the Settlement, many of which have already been put in place. The Settlement does not include any admission of liability. In October 2024, the District Court issued an Order and Judgment approving the Settlement and granted an Order of Dismissal with Prejudice. Under the Settlement, all Derivative Actions have been or will be dismissed, the Litigation Demand has been withdrawn, and those matters and claims have been resolved pursuant to the terms of the Settlement.

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. AEP and the SEC are engaged in discussions about a possible resolution of the SEC's investigation and potential claims under the securities laws. Based on these discussions, in the third quarter of 2024, AEP recorded a loss contingency of $19 million in Other Operation expenses on AEP's statements of income and accrued a corresponding liability in Other Current Liabilities on AEP's balance sheets. A resolution of the investigation or claims may subject AEP to civil penalties in an amount that could differ from the amount recorded; however, management does not believe any such resolution would be material.

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 assertions related to the CCR Rule (see "CCR Rule" section below for additional information), including an assertion 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 any determinations of noncompliance by the Federal EPA with various aspects of the CCR Rule consistent with 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, which in June 2024, were dismissed for lack of jurisdiction. In January 2024, Gavin Power LLC also filed a complaint with the United States District Court for the Southern District of Ohio, alleging various violations of the Administrative Procedure Act and asserting that the Federal EPA, through its prior inaction, has waived and is estopped from raising certain objections raised in the Gavin Denial. Management cannot predict the outcome of that litigation. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Litigation Regarding Justice Thermal Coal Contract

In December 2023, APCo filed a suit in the Franklin County Ohio Court of Common Pleas seeking a declaratory judgment confirming APCo's right to terminate a long-term coal contract with Justice Thermal LLC (Justice Thermal) based on Justice Thermal's failure to perform under the contract. APCo terminated that contract in January 2024, and in April 2024, APCo filed an amended complaint seeking a declaration that the termination was proper and also seeking damages for Justice Thermal's breach of contract. Justice Thermal filed an answer and counterclaim in April 2024, contesting the validity of the contract termination and asserting counterclaims. The parties entered into a Settlement Agreement and Release pursuant to which the litigation was dismissed with prejudice in September 2024 and each party released the other from all claims relating to the contract or the litigation, and as a result this matter has been resolved.

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.

Impact of Environmental Compliance on the Generating Fleet

The rules and environmental control requirements discussed below will have a material impact on AEP's operations. As of September 30, 2024, AEP owned generating capacity of approximately 23,000 MWs, of which approximately 10,700 MWs were coal-fired. In April 2024, the Federal EPA announced four major new rules directed at fossil-fuel electric generation facilities. Management continues to evaluate the impacts of these rules on the plans for the future of AEP's generating fleet, in particular, the economic feasibility of making the requisite environmental investments on AEP's fossil generation fleet. AEP continues to refine the cost estimates of complying with these rules to identify the best alternative for ensuring compliance with all of the rules while meeting AEP's obligations to provide reliable and affordable electricity.

The costs of complying with new rules may also change based on: (a) potential state rules that impose additional more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) actual performance of the pollution control technologies installed, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

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 GHG 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 CAA. Revisions 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 February 2024, the Federal EPA finalized a new more stringent annual primary $PM_{2.5}$ standard.

Areas with air quality that does not meet the new standard will be designated by the Federal EPA as "nonattainment," which will trigger an obligation for states to revise their SIPs to include additional requirements, resulting in further emission reductions to ensure that the new standard will be met. Areas around some of AEP's generating facilities may be deemed nonattainment, which may require those facilities to install additional pollution controls or to implement operational constraints. The nonattainment designations by the Federal EPA and the subsequent SIP revisions by the affected states will take some time to complete; therefore, management cannot reasonably estimate the impact on AEP's operations, cash flows, net income or financial condition.

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. Petitions for review of the final rule revisions were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In early 2018, the Federal EPA announced plans to revisit aspects of the final rule raised by petitioners in petitions for administrative reconsideration, and the court granted the Federal EPA's motion to hold the litigation in abeyance.

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. Environmental groups filed challenges to these various rulemakings in district courts in the Fifth Circuit and the District of Columbia Circuit. Management cannot predict the outcome of that litigation, although management supports the intrastate trading program as a compliance alternative to source-specific controls and intervened in the Fifth Circuit litigation in support of the Federal EPA. In July 2024, the U.S. District Court for the District of Columbia Circuit entered a consent decree setting deadlines for the Federal EPA to rule on Regional Haze SIPs for 33 states, including Texas. In September 2024, the Federal EPA signed a proposed rule to partially approve and partially disapprove the Texas SIP revision. The proposed rule was published in the Federal Register in October 2024, initiating a public comment period ending November 14, 2024. The deadline for the Federal EPA to take final action on the Texas SIP is May 30, 2025.

Cross-State Air Pollution Rule

CSAPR is a regional trading program that the Federal EPA began implementing in 2015, which was originally designed to address interstate transport of emissions that contribute significantly to nonattainment and interfere with maintenance of the 1997 ozone NAAQS and the 1997 and 2006 $PM_{2.5}$ 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. AEP has been able to meet the requirements of the revised rule over the first few years of implementation, 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, including Texas, addressing the 2015 Ozone NAAQS. The Federal EPA disapproved interstate transport SIPs submitted by additional states soon thereafter. Disapproval of the SIPs provided the Federal EPA with authority to impose a FIP for those states, replacing the SIPs that were disapproved. In August 2023, a FIP (the Good Neighbor Plan) went into effect that further revised the ozone season NO_X budgets under the existing CSAPR program in states to which the FIP applies. As a result of several separate legal challenges brought by states and industry parties in various federal courts, implementation of the FIP has been stayed in all of the states in which AEP operates. In October 2024, the Federal EPA issued a final rule to administratively stay the effectiveness of the Good Neighbor Plan's requirements for all sources covered by that rule as promulgated where an administrative stay was not already in place. The administrative stay of the Good Neighbor Plan's effectiveness for power plants and other industrial facilities in each of the 23 states will remain in place until the Supreme Court lifts its order staying enforcement of the Good Neighbor Plan, other courts lift any judicial orders staying the SIP disapproval action as to the state, and the Federal EPA takes subsequent rulemaking action consistent with any judicial rulings on the merits. Management will continue to monitor the outcome of this litigation and the development of SIPs for any potential impact to operations.

Climate Change, CO_2 Regulation and Energy Policy

In April 2024, the Administrator of the Federal EPA signed new GHG standards and guidelines for new and existing fossil-fuel fired sources. The rule relies on carbon capture and sequestration and natural gas co-firing as means to reduce CO_2 emissions from coal fired plants and carbon capture and sequestration or limited utilization to reduce CO_2 emissions from new gas turbines. The rule also offers early retirement of coal plants in lieu of carbon capture and storage as an alternative means of compliance. The Federal EPA deferred the finalization of standards for existing gas turbines until later in 2024. AEP is in the early stages of evaluating and identifying the best strategy for complying with this and other new rules, discussed below, while ensuring the adequacy of resources to meet customer needs. The rule has been challenged by 27 states, numerous companies, trade associations and others. AEP has joined with several other utilities to challenge the rule and has asked the court to stay the rule during the litigation, and the appeals have been consolidated. In July 2024, the U.S. Court of Appeals for the District of Columbia Circuit denied those motions to stay and several parties, including AEP and other utilities, filed applications with the United States Supreme Court seeking an emergency stay. The Supreme Court denied those applications in October 2024 and the litigation will continue to proceed before the U.S. Court of Appeals for the District of Columbia Circuit. Excessive costs to comply with environmental regulations have led to the announcement of early plant closures across the country. The Federal EPA's new GHG rules, and suite of other new rules issued simultaneously which are discussed below, are directed at the fossil-fuel fired electric utility industry 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.

AEP routinely submits IRPs in various regulatory jurisdictions to address future generation and capacity needs. These IRPs take into account economics, customer demand, grid reliability and resilience, regulations and RTO capacity requirements. The objective of the IRPs is to recommend future generation and capacity resources that provide the most cost-efficient and reliable power to customers. Based on the output of these IRPs, in October 2022, AEP modified its intermediate and long-term GHG emission reduction goals. The intermediate goal is an 80% reduction in Scope 1 GHG emissions by 2030 (from a 2005 baseline) and the long-term goal is net-zero Scope 1 and Scope 2 GHG emissions by 2045. AEP's total Scope 1 GHG estimated emissions in 2023 were approximately 43.4 million metric tons, a 68% reduction according to the GHG Protocol, which excludes emission reductions that result from assets that have been sold, or a 71% reduction from AEP's 2005 Scope 1 GHG emissions (inclusive of emission reductions that result from plants that have been sold). AEP expects its Scope 1 GHG emissions to vary annually depending on the proportion of its own generation and purchased power used to serve customers as well as load growth on the system.

AEP has made significant progress in reducing CO_2 emissions from its power generation fleet and expects its emissions to continue to decline over the long-term due to the retirement of certain fossil fuel generation units and increased energy efficiency, where there is regulatory support for such activities. AEP's ability to achieve its GHG emission goals, and the modification of such goals in the future, are dependent upon a number of factors including continuing to provide the most cost-efficient and reliable power to customers, changes in load growth across our service territory, IRPs submitted in various jurisdictions and the preferences of state regulators and policymakers for dispatchable or renewable generation resources, evolving RTO requirements, the advancement of carbon-free generation technologies, customer demand for carbon-free energy, potential tariffs, carbon policy and regulation, operational performance of renewable generation, supply chain costs and constraints, and ability to use carbon offsets. Based on AEP's most recent analysis, AEP currently projects that achievement of its net-zero Scope 1 and Scope 2 emissions by 2045 long-term goal would require the development of new carbon-free generation technologies, a decline in forecasted customer load, use of carbon offsets or other future changes.

MATS Rule

In April 2024, the Federal EPA issued a revised MATS rule for power plants. The 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 rule also requires the installation and operation of continuous emissions monitors for PM. Several states and other parties have challenged the rule in the United States Court of Appeals for the District of Columbia Circuit, but management cannot predict the outcome of the litigation. Management is evaluating the impacts of the rule, but does not anticipate any significant challenges complying with the rule.

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 original rule applied to active and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers. With revisions announced in April 2024, the scope of the rule has expanded significantly, 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").

In 2020, the Federal EPA revised the original 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 provided 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 requires 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 had filed several applications for additional time to develop alternative disposal capacity at the various plants. AEP has since ceased receiving ash in the ponds subject to the extension requests, completed construction of new CCR Rule compliant facilities and has withdrawn those applications as moot.

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 Gavin Denial, discussed above). The Federal EPA's allegations of noncompliance rely on what AEP and others believe are new interpretations of the CCR Rule requirements. The new interpretations in the January

Actions of the Federal EPA and the Gavin Denial were 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. In June 2024, the United States Court of Appeals for the District of Columbia Circuit held that the Federal EPA's January actions and statements made in the Gavin Denial did not constitute new agency rules subject to review by the court. The court dismissed the appeals for lack of jurisdiction.

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 had 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. To date, the Federal EPA has not taken any action on the pending extension request for the Welsh Plant.

In April 2024, the Federal EPA finalized 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"). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all of the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. Closure may be accomplished by applying an impermeable cover system over the CCR material ("closure in place") or the CCR material may be excavated and placed in a compliant landfill ("closure by removal"). Groundwater monitoring and other analysis over the next three years will provide additional information on the planned closure method. AEP evaluated the applicability of the rule to current and former plant sites and recorded incremental ARO in the second quarter of 2024, as shown in the table below, based on initial cost estimates primarily reflecting compliance with the rule through closure in place and future groundwater monitoring requirements pursuant to the CCR Rule.

Registrant	Increase in ARO	Increase in Generation Property (a)	Increase in Regulatory Assets (b)	Charged to Operating Expenses (c)
		(in millions)		
APCo	$ 312.2	$ 75.6	$ 236.6	$ —
I&M	85.7	—	72.3	13.4
OPCo	52.9	—	—	52.9
PSO	33.7	33.7	—	—
SWEPCo	23.8	23.8	—	—
Non-Registrants	166.1	43.8	46.1	76.2
Total	$ 674.4	$ 176.9	$ 355.0	$ 142.5

(a) ARO is related to a legacy CCR surface impoundment or CCR management unit at an operating generation facility.
(b) ARO is related to a legacy CCR surface impoundment or CCR management unit at a retired generation facility and recognition of a regulatory asset in accordance with the accounting guidance for "Regulated Operations" is supported.
(c) ARO is related to a legacy CCR surface impoundment or CCR management unit and recognition of a regulatory asset in accordance with the accounting guidance for "Regulated Operations" is not yet supported.

As further groundwater monitoring and other analysis is performed, management expects to refine the assumptions and underlying cost estimates used in recording the ARO. These refinements may include, but are not limited to, changes in the expected method of closure, changes in estimated quantities of CCR at each site, the identification of new CCR management units, among other items. These future changes could have a material impact on the ARO and materially reduce future net income and cash flows and further impact financial condition.

AEP will seek cost recovery through regulated rates, including proposal of new regulatory mechanisms for cost recovery where existing mechanisms are not applicable. The rule could have an additional, material adverse impact on net income, cash flows and financial condition if AEP cannot ultimately recover these additional costs of compliance. Several parties, including AEP and one of its trade associations, have filed petitions for review of the rule with the U.S. Court of Appeals for the D.C. Circuit. One of the parties also filed a motion to stay the rule pending the outcome of the litigation. In November 2024, the court denied the stay motion. Management cannot predict the outcome of the litigation.

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 required to 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 April 2024, the Federal EPA finalized further revisions to the ELG rule that establish a zero liquid discharge standard for FGD wastewater, bottom ash transport water, and managed combustion residual leachate, as well as more stringent discharge limits for unmanaged combustion residual leachate. The revised rule provides a new compliance alternative that would avoid the need to install zero liquid discharge systems for facilities that comply with the 2020 rule's control technology requirements and commit by December 31, 2025 to retire by 2034. Management is evaluating the compliance alternatives in the rule, taking into consideration the requirements of the other new rules and their combined impacts to operations. Several appeals have been filed with various federal courts challenging the 2024 ELG rule. SWEPCo has also challenged the rule, by filing a joint appeal with a utility trade association in which AEP participates. The various appeals have been consolidated before the United States Court of Appeals for the Eighth Circuit. SWEPCo and the utility trade association filed a motion to stay the rule during the litigation, but in October 2024, the court denied the motion. Management cannot predict the outcome of the litigation.

The definition of "waters of the United States" has been subject to rule-making and litigation which has led to inconsistent scope among the states. Management will continue to monitor developments in rule-making and litigation for any potential impact to operations.

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 September 30, 2024, 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	$ 111.9	$ 181.2	2026	(c)	$ 15.7
SWEPCo	Pirkey Plant	—	120.8 (d)	2023	(e)	—
SWEPCo	Welsh Plant, Units 1 and 3	341.4	156.7	2028 (f)	(g)	41.6

(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. See the "Regulated Generating Units" section of Note 4 for additional information.
(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

AEP's Reportable Segments

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

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

The remainder of AEP's activities are presented as Corporate and Other, which is not considered a reportable segment. See Note 8 - Business Segments for additional information on AEP's segments.

The following discussion of AEP's results of operations by operating segment provides a comparison of Earnings Attributable to AEP Common Shareholders for the three months ended and nine months ended September 30, 2024 as compared to the three months ended and nine months ended September 30, 2023. For AEP's Vertically Integrated Utilities and Transmission and Distribution Utilities segments and subsidiary registrants within these segments, the results include revenues from rate rider mechanisms designed to recover fuel, purchased power and other recoverable expenses such that the revenues and expenses associated with these items generally offset and do not affect Earnings Attributable to AEP Common Shareholders. For additional information regarding the financial results for the three and nine months ended September 30, 2024 and 2023, see the discussions of Results of Operations by Subsidiary Registrant.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in millions)			
Vertically Integrated Utilities	$ 571.5	$ 512.5	$ 1,198.0	$ 1,051.6
Transmission and Distribution Utilities	245.2	206.0	542.3	508.4
AEP Transmission Holdco	214.7	202.9	624.1	580.8
Generation & Marketing	93.3	130.7	226.1	(59.3)
Corporate and Other	(165.1)	(98.4)	(287.5)	(209.6)
Earnings Attributable to AEP Common Shareholders	$ 959.6	$ 953.7	$ 2,303.0	$ 1,871.9

Three Months Ended September 30, 2024

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
	(in millions)			
Revenues	$ 3,303.0	$ 1,575.4	$ 512.5	$ 499.1
Fuel, Purchased Electricity and Other	1,100.4	213.2	—	413.6
Other Operation and Maintenance	881.6	599.1	40.0	20.6
Depreciation and Amortization	530.6	212.8	110.5	4.0
Taxes Other Than Income Taxes	138.1	181.6	81.2	0.8
Operating Income	652.3	368.7	280.8	60.1
Other Income	5.7	4.0	3.4	8.2
Allowance for Equity Funds Used During Construction	12.9	17.0	24.3	—
Non-Service Cost Components of Net Periodic Benefit Cost	26.5	11.3	1.4	5.9
Interest Expense	(189.9)	(106.4)	(56.2)	(4.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings	507.5	294.6	253.7	70.2
Income Tax Expense (Benefit)	(64.6)	49.4	60.9	(23.1)
Equity Earnings of Unconsolidated Subsidiary	0.4	—	23.0	—
Net Income	572.5	245.2	215.8	93.3
Net Income Attributable to Noncontrolling Interests	1.0	—	1.1	—
Earnings Attributable to AEP Common Shareholders	$ 571.5	$ 245.2	$ 214.7	$ 93.3

Three Months Ended September 30, 2023

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
	(in millions)			
Revenues	$ 3,205.4	$ 1,544.1	$ 476.7	$ 566.7
Fuel, Purchased Electricity and Other	1,137.5	298.8	—	406.6
Other Operation and Maintenance	829.4	541.1	39.3	31.2
Depreciation and Amortization	480.7	206.9	101.9	8.3
Taxes Other Than Income Taxes	131.9	181.3	75.5	1.6
Operating Income	625.9	316.0	260.0	119.0
Other Income	5.9	0.6	2.1	11.5
Allowance for Equity Funds Used During Construction	15.0	13.4	22.7	—
Non-Service Cost Components of Net Periodic Benefit Cost	31.6	14.1	1.5	6.6
Interest Expense	(197.1)	(93.8)	(53.6)	(18.7)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	481.3	250.3	232.7	118.4
Income Tax Expense (Benefit)	(32.4)	44.3	51.1	(16.2)
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.3	—	22.3	(1.8)
Net Income	514.0	206.0	203.9	132.8
Net Income Attributable to Noncontrolling Interests	1.5	—	1.0	2.1
Earnings Attributable to AEP Common Shareholders	$ 512.5	$ 206.0	$ 202.9	$ 130.7

Nine Months Ended September 30, 2024

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
	(in millions)			
Revenues	$ 8,869.9	$ 4,501.5	$ 1,499.7	$ 1,530.1
Fuel, Purchased Electricity and Other	2,970.3	729.0	—	1,151.0
Other Operation and Maintenance	2,720.1	1,639.0	122.8	94.5
Asset Impairments and Other Related Charges	13.4	52.9	—	76.2
Depreciation and Amortization	1,470.4	662.2	327.5	17.3
Taxes Other Than Income Taxes	410.7	550.4	233.4	1.5
Operating Income	1,285.0	868.0	816.0	189.6
Other Income	17.0	7.5	10.3	28.6
Allowance for Equity Funds Used During Construction	37.4	50.9	64.7	—
Non-Service Cost Components of Net Periodic Benefit Cost	73.8	31.4	2.5	17.6
Interest Expense	(537.3)	(298.4)	(166.4)	(14.9)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	875.9	659.4	727.1	220.9
Income Tax Expense (Benefit)	(324.5)	116.3	172.2	(4.3)
Equity Earnings (Loss) of Unconsolidated Subsidiary	1.1	(0.8)	72.6	0.9
Net Income	1,201.5	542.3	627.5	226.1
Net Income Attributable to Noncontrolling Interests	3.5	—	3.4	—
Earnings Attributable to AEP Common Shareholders	$ 1,198.0	$ 542.3	$ 624.1	$ 226.1

Nine Months Ended September 30, 2023

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing
	(in millions)			
Revenues	$ 8,737.7	$ 4,348.5	$ 1,390.8	$ 1,225.1
Fuel, Purchased Electricity and Other	2,989.0	970.5	—	1,116.0
Other Operation and Maintenance	2,480.7	1,472.7	109.9	130.4
Loss on the Sale of the Competitive Contracted Renewable Portfolio	—	—	—	112.0
Depreciation and Amortization	1,411.3	576.2	297.9	34.7
Taxes Other Than Income Taxes	390.8	519.1	222.0	6.1
Operating Income (Loss)	1,465.9	810.0	761.0	(174.1)
Other Income	20.2	1.9	7.0	32.2
Allowance for Equity Funds Used During Construction	30.5	30.7	62.2	—
Non-Service Cost Components of Net Periodic Benefit Cost	94.9	42.1	4.6	19.7
Interest Expense	(565.1)	(270.0)	(153.7)	(69.2)
Income (Loss) Before Income Tax Expense (Benefit) and Equity Earnings	1,046.4	614.7	681.1	(191.4)
Income Tax Expense (Benefit)	(7.2)	106.3	158.7	(127.3)
Equity Earnings of Unconsolidated Subsidiary	1.0	—	61.2	1.9
Net Income (Loss)	1,054.6	508.4	583.6	(62.2)
Net Income (Loss) Attributable to Noncontrolling Interests	3.0	—	2.8	(2.9)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 1,051.6	$ 508.4	$ 580.8	$ (59.3)

VERTICALLY INTEGRATED UTILITIES

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in millions of KWhs)			
Retail:				
Residential	8,959	8,975	24,191	23,406
Commercial	6,910	6,686	18,763	17,781
Industrial	8,562	8,731	25,563	25,686
Miscellaneous	612	618	1,718	1,684
Total Retail	25,043	25,010	70,235	68,557
Wholesale (a)	3,559	3,876	10,498	10,620
Total KWhs	28,602	28,886	80,733	79,177

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

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,302	1,253
Normal – Heating (b)	3	3	1,746	1,750
Actual – Cooling (c)	854	748	1,328	967
Normal – Cooling (b)	746	751	1,089	1,095
Western Region				
Actual – Heating (a)	—	—	743	657
Normal – Heating (b)	1	—	910	916
Actual – Cooling (c)	1,510	1,634	2,486	2,436
Normal – Cooling (b)	1,434	1,430	2,173	2,162

(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 2023 to 2024 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Earnings Attributable to AEP Common Shareholders	$ 512.5	$ 1,051.6
Changes in Revenues:		
Retail Revenues	42.6	36.6
Off-system Sales	24.7	28.3
Transmission Revenues	24.4	39.0
Other Revenues	5.9	28.3
Total Change in Revenues	97.6	132.2
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	37.1	18.7
Other Operation and Maintenance	(52.2)	(239.4)
Asset Impairments and Other Related Charges	—	(13.4)
Depreciation and Amortization	(49.9)	(59.1)
Taxes Other Than Income Taxes	(6.2)	(19.9)
Other Income	(0.2)	(3.2)
Allowance for Equity Funds Used During Construction	(2.1)	6.9
Non-Service Cost Components of Net Periodic Pension Cost	(5.1)	(21.1)
Interest Expense	7.2	27.8
Total Change in Expenses and Other	(71.4)	(302.7)
Income Tax Benefit	32.2	317.3
Equity Earnings of Unconsolidated Subsidiary	0.1	0.1
Net Income Attributable to Noncontrolling Interests	0.5	(0.5)
2024 Earnings Attributable to AEP Common Shareholders	$ 571.5	$ 1,198.0

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Retail Revenues** increased $43 million primarily due to the following:
  - A $30 million increase in rider revenues at APCo and WPCo.
  - A $23 million increase in rates due to the 2020-2022 Virginia Triennial Review at APCo.
  - A $19 million increase in rider revenues at KPCo.
  - A $15 million increase in rider revenues at I&M.
  - A $10 million increase in weather-normalized revenues primarily in the residential and commercial classes, partially offset by a decrease in the industrial class.

  These increases were partially offset by:
  - A $50 million decrease in fuel revenues primarily due to lower authorized fuel rates at PSO.
  - A $12 million decrease due to regulatory provisions for refund at I&M.
- **Off-system Sales** increased $25 million primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales at I&M.
- **Transmission Revenues** increased $24 million primarily due to continued investment in transmission assets.
- **Other Revenues** increased $6 million primarily due to an increase in sales of renewable energy credits and pole attachment revenue.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** decreased $37 million primarily due to decreases at PSO, SWEPCo and I&M, partially offset by an increase at APCo.
- **Other Operation and Maintenance expenses** increased $52 million primarily due to the following:
  - A $37 million increase in PJM and SPP transmission services.
  - A $20 million increase due to prior year proceeds for insurance policy settlements.
- **Depreciation and Amortization** increased $50 million primarily due to a higher depreciable base at APCo, PSO and SWEPCo, an increase in regulatory reserves related to the recognition of Nuclear PTCs at I&M and an increase in amortization of regulatory assets at PSO and SWEPCo.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to increased property taxes at APCo, KPCo and PSO.
- **Non-Service Cost Components of Net Periodic Pension Cost** increased $5 million primarily due to the expiration of prior service credit amortization from previous plan changes, partially offset by lower loss amortization resulting from favorable asset returns during 2023 and lower interest costs due to lower discount rates.
- **Interest Expense** decreased $7 million primarily due to the prior year amortization of carrying charges on storm-related regulatory assets at SWEPCo.
- **Income Tax Benefit** increased $32 million primarily due to the following:
  - A $61 million increase due to estimated Nuclear PTCs at I&M.

  This increase was partially offset by:
  - A $22 million decrease due to a decrease in amortization of Excess ADIT.
  - A $6 million decrease due to a decrease in pretax book income.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Retail Revenues** increased $37 million primarily due to the following:
  - A $91 million increase in rider revenues at APCo and WPCo.
  - A $91 million increase in weather-related usage primarily in the residential class driven by a 12% increase in cooling degree days.
  - A $60 million increase in rates at APCo due to the 2020-2022 Virginia Triennial Review.
  - A $49 million increase in rider revenues at KPCo.
  - A $32 million increase in base rate and rider revenues at PSO.
  - A $12 million increase at I&M due to the implementation of new base rates in Indiana and Michigan.
  - A $9 million increase in rider revenues at I&M.

  These increases were partially offset by:
  - A $176 million decrease at SWEPCo primarily due to the recognition of a $160 million probable revenue refund associated with the Turk Plant and SWEPCo's 2012 Texas Base Rate Case.
  - A $106 million decrease in fuel revenues primarily due to lower authorized fuel rates at PSO.
  - A $34 million decrease due to regulatory provisions for refund at I&M.
- **Off-system Sales** increased $28 million primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales at I&M.
- **Transmission Revenues** increased $39 million primarily due to continued investment in transmission assets.
- **Other Revenues** increased $28 million primarily due to associated business development revenues at PSO and SWEPCo and pole attachment revenue at APCo.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $19 million primarily due to decreases at PSO and SWEPCo, partially offset by increases at APCo and I&M.
- **Other Operation and Maintenance** expenses increased $239 million primarily due to the following:
  - A $111 million increase in PJM and SPP transmission services.
  - A $76 million increase in employee-related expenses due to the voluntary severance program.
  - A $20 million increase due to prior year proceeds for insurance policy settlements.
  - A $14 million increase due to a disallowance recorded on the remaining net book value of the Dolet Hills Power Station as a result of an LPSC approved settlement agreement in April 2024.

- **Asset Impairments and Other Related Charges** increased $13 million due to the Federal EPA's revised CCR rules.
- **Depreciation and Amortization** expenses increased $59 million primarily due to the following:
  - A $31 million increase at SWEPCo primarily due to an increase in amortization of regulatory assets and a higher depreciable base, partially offset by the recognition of a regulatory asset related to NOLCs.
  - A $20 million increase at APCo primarily due to a higher depreciable base.
  - A $14 million increase at PSO primarily due to a higher depreciable base, implementation of new rates and the amortization of regulatory assets related to NCWF.
- **Taxes Other Than Income Taxes** increased $20 million primarily due to increased property taxes at PSO, I&M and KPCo and an increase in Virginia state minimum taxes at APCo, partially offset by a decrease in property taxes at SWEPCo.
- **Allowance for Equity Funds Used During Construction** increased $7 million primarily due to higher CWIP and AFUDC equity rates.
- **Non-Service Cost Components of Net Periodic Benefit Cost** increased $21 million primarily due to the expiration of prior service credit amortization from previous plan changes, partially offset by lower loss amortization resulting from favorable asset returns during 2023 and lower interest costs due to lower discount rates.
- **Interest Expense** decreased $28 million primarily due to the recognition of debt carrying charges as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail rate making.
- **Income Tax Benefit** increased $317 million primarily due to the following:
  - A $212 million increase due to a reduction in Excess ADIT regulatory liabilities at I&M, PSO, and SWEPCo as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs.
  - A $61 million increase due to estimated Nuclear PTCs at I&M.
  - A $32 million increase due to a reduction in Excess ADIT regulatory liabilities as a result of the APSC's denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers.

TRANSMISSION AND DISTRIBUTION UTILITIES

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in millions of KWhs)			
Retail:				
Residential	8,206	8,442	21,079	20,618
Commercial	9,671	8,574	26,871	22,711
Industrial	6,725	6,601	20,363	19,800
Miscellaneous	213	220	573	565
Total Retail (a)	24,815	23,837	68,886	63,694
Wholesale (b)	504	485	1,347	1,366
Total KWhs	25,319	24,322	70,233	65,060

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in degree days)			
Eastern Region				
Actual – Heating (a)	—	—	1,573	1,521
Normal – Heating (b)	4	4	2,056	2,080
Actual – Cooling (c)	844	625	1,266	809
Normal – Cooling (b)	699	697	1,008	1,005
Western Region				
Actual – Heating (a)	—	—	162	143
Normal – Heating (b)	—	—	198	197
Actual – Cooling (d)	1,457	1,719	2,801	2,945
Normal – Cooling (b)	1,401	1,387	2,487	2,454

(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 2023 to 2024 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Earnings Attributable to AEP Common Shareholders	$ 206.0	$ 508.4
Changes in Revenues:		
Retail Revenues	9.0	90.9
Off-system Sales	(2.1)	(11.7)
Transmission Revenues	16.6	47.8
Other Revenues	7.8	26.0
Total Change in Revenues	31.3	153.0
Changes in Expenses and Other:		
Purchased Electricity for Resale	61.6	278.1
Purchased Electricity from AEP Affiliates	23.9	(36.6)
Other Operation and Maintenance	(57.9)	(166.3)
Asset Impairments and Other Related Charges	—	(52.9)
Depreciation and Amortization	(5.9)	(86.0)
Taxes Other Than Income Taxes	(0.3)	(31.3)
Other Income	3.4	5.6
Allowance for Equity Funds Used During Construction	3.6	20.2
Non-Service Cost Components of Net Periodic Benefit Cost	(2.8)	(10.7)
Interest Expense	(12.6)	(28.4)
Total Change in Expenses and Other	13.0	(108.3)
Income Tax Expense	(5.1)	(10.0)
Equity Earnings (Loss) of Unconsolidated Subsidiary	—	(0.8)
2024 Earnings Attributable to AEP Common Shareholders	$ 245.2	$ 542.3

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Retail Revenues** increased $9 million primarily due to the following:
  - A $130 million increase in revenue from rate riders.

  This increase was partially offset by:
  - A $104 million decrease due to lower customer participation in OPCo's SSO, partially offset by higher prices.
  - A $20 million decrease in weather-normalized revenues in the industrial class in Ohio and in the residential class in Texas.
- **Transmission Revenues** increased $17 million primarily due to the following:
  - A $10 million increase in interim rates driven by increased transmission investments in Texas.
  - A $6 million increase due to increased load in Texas.
- **Other Revenues** increased $8 million primarily due to the following:
  - A $13 million increase primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.

  This increase was partially offset by:
  - A $5 million decrease in securitization revenue in Texas.

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

- **Purchased Electricity for Resale** expenses decreased $62 million primarily due to the following:
  - An $80 million decrease in recoverable auction purchases primarily due to lower volumes driven by lower customer participation in OPCo’s SSO.

  This decrease was partially offset by:
  - A $19 million increase in recoverable OVEC costs.
- **Purchased Electricity from AEP Affiliates** expenses decreased $24 million primarily due to decreased recoverable auction purchases in OPCo’s SSO.
- **Other Operation and Maintenance** expenses increased $58 million primarily due to the following:
  - A $31 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $12 million increase in distribution-related expenses in Ohio and Texas.
  - An $11 million increase related to recoverable energy assistance program expenses for qualified Ohio customers.
- **Depreciation and Amortization** expenses increased $6 million primarily due to an increase in recoverable rider depreciable assets in Ohio.
- **Interest Expense** increased $13 million primarily due to higher debt balances and interest rates.
- **Income Tax Expense** increased $5 million primarily due to an increase in pretax book income.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Retail Revenues** increased $91 million primarily due to the following:
  - A $352 million increase in revenue from rate riders.
  - A $44 million increase in weather-related usage in Ohio driven by a 56% increase in cooling degree days.

  These increases were partially offset by:
  - A $306 million decrease due to lower customer participation in OPCo’s SSO, partially offset by higher prices in Ohio.
- **Off-system Sales** decreased $12 million primarily due to 2023 PJM settlements related to winter storm Elliott.
- **Transmission Revenues** increased $48 million primarily due to the following:
  - A $29 million increase in interim rates driven by increased transmission investment in Texas.
  - An $18 million increase due to increased load in Texas.
- **Other Revenues** increased $26 million primarily due to the following:
  - A $33 million increase due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.

  This increase was partially offset by:
  - A $9 million decrease in recoverable sales of renewable energy credits in Ohio.

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

- **Purchased Electricity for Resale** expenses decreased $278 million primarily due to the following:
  - A $342 million decrease in recoverable auction purchases primarily due to lower volumes driven by lower customer participation in OPCo’s SSO, partially offset by higher prices.
  - A $16 million decrease in recoverable alternative energy rider expenses in Ohio.

  These decreases were partially offset by:
  - An $81 million increase in recoverable OVEC costs.
- **Purchased Electricity from AEP Affiliates** expenses increased $37 million primarily due to decreased recoverable auction purchases in OPCo’s SSO.
- **Other Operation and Maintenance** expenses increased $166 million primarily due to the following:
  - A $73 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $35 million increase in employee-related expenses due to the voluntary severance program.
  - A $28 million increase due to a prior year decrease in expenses driven by legislation passed in Texas in May 2023 allowing employee financially based incentives to be recovered.
  - A $19 million increase in distribution expenses in Ohio primarily related to recoverable storm restoration costs and recoverable vegetation management expenses.
  - A $16 million increase related to recoverable energy assistance program expenses for qualified Ohio customers.
- **Asset Impairments and Other Related Charges** increased $53 million due to the Federal EPA's Revised CCR rules.
- **Depreciation and Amortization** expenses increased $86 million primarily due to a higher depreciable base in Ohio and Texas and an increase in recoverable rider depreciable assets in Ohio.

- **Taxes Other Than Income Taxes** increased $31 million primarily due to the following:
  - A $35 million increase due to higher property taxes driven by additional investments in transmission and distribution assets and tax rate changes in Ohio.
  - An $8 million increase in state excise taxes due to increased billed KWh in 2024.

  These increases were partially offset by:
  - A $12 million decrease primarily due to lower property taxes driven by decreased tax rates in Texas.
- **Allowance for Equity Funds Used During Construction** increased $20 million primarily due to higher AFUDC bases in Ohio and Texas.
- **Non-Service Cost Components of Net Periodic Benefit Cost** increased $11 million primarily due to the expiration of prior service credit amortization from previous plan changes partially offset by lower loss amortization resulting from favorable asset returns during 2023 and lower interest costs due to lower discount rates.
- **Interest Expense** increased $28 million primarily due to:
  - A $34 million increase primarily due to higher debt balances and interest rates.

  This increase was partially offset by:
  - A $6 million decrease due to an increase of capitalization of AFUDC on prepaid pension and OPEB.
- **Income Tax Expense** increased $10 million primarily due to:
  - A $9 million increase due to an increase in pretax book income.
  - A $6 million increase due to a decrease in amortization of Excess ADIT in Texas.

  These increases were partially offset by:
  - A $4 million decrease due to a decrease in AFUDC equity.

AEP TRANSMISSION HOLDCO

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	September 30, 2024	September 30, 2023
	(in millions)	
Plant in Service	$ 15,125.0	$ 14,042.9
Construction Work in Progress	2,411.1	2,037.0
Accumulated Depreciation and Amortization	1,555.5	1,261.2
Total Transmission Property, Net	$ 15,980.6	$ 14,818.7

AEP Transmission Holdco

Reconciliation of 2023 to 2024 Earnings Attributable to AEP Common Shareholders

(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Earnings Attributable to AEP Common Shareholders	$ 202.9	$ 580.8
Changes in Transmission Revenues:		
Transmission Revenues	35.8	108.9
Total Change in Transmission Revenues	35.8	108.9
Changes in Expenses and Other:		
Other Operation and Maintenance	(0.7)	(12.9)
Depreciation and Amortization	(8.6)	(29.6)
Taxes Other Than Income Taxes	(5.7)	(11.4)
Interest and Investment Income	1.3	3.3
Allowance for Equity Funds Used During Construction	1.6	2.5
Non-Service Cost Components of Net Periodic Pension Cost	(0.1)	(2.1)
Interest Expense	(2.6)	(12.7)
Total Change in Expenses and Other	(14.8)	(62.9)
Income Tax Expense	(9.8)	(13.5)
Equity Earnings of Unconsolidated Subsidiary	0.7	11.4
Net Income Attributable to Noncontrolling Interests	(0.1)	(0.6)
2024 Earnings Attributable to AEP Common Shareholders	$ 214.7	$ 624.1

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Transmission Revenues** increased $36 million primarily due to continued investment in transmission assets.

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

- **Depreciation and Amortization** expenses increased $9 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to higher property taxes driven by increased transmission investment.
- **Income Tax Expense** increased $10 million primarily due to an increase in pretax book income and an increase in state income taxes.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Transmission Revenues** increased $109 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $13 million primarily due to an $11 million increase in employee-related expenses due to the voluntary severance program.
- **Depreciation and Amortization** expenses increased $30 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $11 million primarily due to higher property taxes driven by increased transmission investment.
- **Interest Expense** increased $13 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $14 million primarily due to an increase in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiary** increased $11 million primarily due to higher pretax earnings at ETT.

GENERATION & MARKETING

Reconciliation of 2023 to 2024 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Earnings Attributable to AEP Common Shareholders	$ 130.7	$ (59.3)
Changes in Revenues:		
Merchant Generation	(6.4)	(13.4)
Renewable Generation	(13.0)	(61.7)
Retail, Trading and Marketing	(48.2)	380.1
Total Change in Revenues	(67.6)	305.0
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(7.0)	(35.0)
Other Operation and Maintenance	10.6	35.9
Asset Impairments and Other Related Charges	—	(76.2)
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	112.0
Depreciation and Amortization	4.3	17.4
Taxes Other Than Income Taxes	0.8	4.6
Other Income	(3.3)	(3.6)
Non-Service Cost Components of Net Periodic Benefit Cost	(0.7)	(2.1)
Interest Expense	14.7	54.3
Total Change in Expenses and Other	19.4	107.3
Income Tax Benefit	6.9	(123.0)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	1.8	(1.0)
Net Income (Loss) Attributable to Noncontrolling Interests	2.1	(2.9)
2024 Earnings Attributable to AEP Common Shareholders	$ 93.3	$ 226.1

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Merchant Generation** decreased $6 million primarily due to lower realized prices in 2024.
- **Renewable Generation** decreased $13 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.
- **Retail, Trading and Marketing** decreased $48 million primarily due to a $48 million unrealized gain on economic hedging activity in 2023 and a $7 million unrealized loss on economic hedging activity in 2024 driven by changes in commodity prices.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $7 million primarily due to an increase in energy costs in 2024.
- **Other Operation and Maintenance** expenses decreased $11 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.
- **Interest Expense** decreased $15 million primarily due to lower advances from affiliates.
- **Income Tax Benefit** increased $7 million primarily due to the following:
  - A $10 million increase due to an increase in amortization of deferred ITCs.
  - A $10 million increase due to a decrease in pretax book income.

  These increases were partially offset by:
  - A $9 million decrease due to a decrease in PTCs.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Merchant Generation** decreased $13 million primarily due to lower realized prices in 2024.
- **Renewable Generation** decreased $62 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.
- **Retail, Trading and Marketing** increased $380 million primarily due to a $221 million unrealized loss on economic hedging activity in 2023 and a $89 million unrealized gain on economic hedging activity in 2024 driven by changes in commodity prices.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $35 million primarily due to an increase in energy costs in 2024.
- **Other Operation and Maintenance** expenses decreased $36 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.
- **Asset Impairments and Other Related Charges** increased $76 million due to the Federal EPA's revised CCR Rules.
- **Loss on the Sale of the Competitive Contracted Renewables Portfolio** decreased $112 million due to the pretax loss on the sale in August 2023.
- **Depreciation and Amortization** expenses decreased $17 million primarily due to the sale of the competitive contracted renewables portfolio in August 2023.
- **Interest Expense** decreased $54 million due to lower advances from affiliates.
- **Income Tax Benefit** decreased $123 million primarily due to:
  - An $86 million decrease due to an increase in pretax book income.
  - A $45 million decrease due to a decrease in PTCs.

  These decreases were partially offset by:
  - A $10 million increase due to an increase in amortization of deferred ITCs.

CORPORATE AND OTHER

Third Quarter of 2024 Compared to Third Quarter of 2023

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $98 million in 2023 to a loss of $165 million in 2024 primarily due to:

- A $19 million loss contingency recorded in 2024 associated with the SEC investigation.
- A $17 million increase in Interest Expense due to higher interest rates and the cancellation of an interest rate swap.
- A $17 million increase in insurance reserves.
- A $12 million decrease in interest income primarily due to lower advances to affiliates.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $210 million in 2023 to a loss of $288 million in 2024 primarily due to:

- A $61 million decrease in interest income primarily due to lower advances to affiliates.
- A $31 million increase in interest expense due to higher interest rates and the cancellation of an interest rate swap.
- A $28 million decrease due to a prior-year adjustment driven by the termination of the sale of the Kentucky operations.
- A $19 million loss contingency recorded in 2024 associated with the SEC investigation.
- A $17 million increase in insurance reserves.

These decreases in earnings were partially offset by:

- A $46 million decrease in corporate expenses.
- A $30 million decrease in Income Tax Expense primarily due to a decrease in pretax book income.

AEP CONSOLIDATED INCOME TAXES

Third Quarter of 2024 Compared to Third Quarter of 2023

Income Tax Expense decreased $27 million primarily due to:

- A $51 million decrease due to estimated Nuclear PTCs.
- A $9 million decrease due to a decrease in state income tax expense.

These decreases were partially offset by:

- A $30 million increase due to a decrease in amortization of Excess ADIT.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

Income Tax Expense decreased $201 million primarily due to:

- A $212 million decrease due to a reduction in Excess ADIT regulatory liabilities at I&M, PSO and SWEPCo as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail rate making.
- A $51 million decrease due to estimated Nuclear PTCs.
- A $32 million decrease due to the reversal of a regulatory liability related to the merchant portion of Turk Plant Excess ADIT as a result of the APSC's March 2024 denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers.

These decreases were partially offset by:

- A $49 million increase due to an increase in pretax book income.
- A $29 million increase due to a decrease in unprotected amortization of Excess ADIT.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	September 30, 2024		December 31, 2023	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 41,974.4	59.7 %	$ 40,143.2	58.8 %
Short-term Debt	1,659.6	2.4	2,830.2	4.2
Total Debt	43,634.0	62.1	42,973.4	63.0
AEP Common Equity	26,617.4	37.9	25,246.7	37.0
Noncontrolling Interests	41.4	—	39.2	—
Total Debt and Equity Capitalization	$ 70,292.8	100.0 %	$ 68,259.3	100.0 %

AEP's ratio of debt-to-total capital decreased from 63.0% to 62.1% as of December 31, 2023 and September 30, 2024, respectively, primarily due to an increase in earnings and equity issued under the ATM program in 2024, partially offset by an increase in long-term debt to support distribution and transmission 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 September 30, 2024, AEP had $6 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 there is an increase in 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 continues monitoring the current bank environment and any impacts thereof. AEP was not materially impacted by these conditions during the nine months ended September 30, 2024.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of September 30, 2024, available liquidity was approximately $5.5 billion as illustrated in the table below:

	Amount	Maturity (a)
Commercial Paper Backup:	(in millions)	
Revolving Credit Facility	$ 5,000.0	March 2029
Revolving Credit Facility	1,000.0	March 2027
Cash and Cash Equivalents	245.8	
Total Liquidity Sources	6,245.8	
Less: AEP Commercial Paper Outstanding	755.0	
Net Available Liquidity	$ 5,490.8	

(a) In March 2024, AEP increased its $4 billion Revolving Credit Facility to $5 billion and extended the maturity date from March 2027 to March 2029. Also, in March 2024, AEP extended the maturity date of its $1 billion Revolving Credit Facility from March 2025 to March 2027.

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. The maximum amount of commercial paper outstanding during the first nine months of 2024 was $2.9 billion. The weighted-average interest rate for AEP's commercial paper during 2024 was 5.55%.

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 September 30, 2024 was $236 million with maturities ranging from October 2024 to July 2025.

Securitized Accounts Receivables

AEP Credit's receivables securitization agreement provides a commitment of $900 million from bank conduits to purchase receivables and expires in September 2026. As of September 30, 2024, 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 September 30, 2024, this contractually-defined percentage was 58.8%. 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 $100 million, would cause an event of default under these credit agreements. This condition also applies, at the more restrictive level of $50 million of debt outstanding, 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 program that allows AEP to issue, from time to time, shares of its common stock, including shares of common stock that may be sold pursuant to an equity forward sales agreement. As of September 30, 2024, approximately $1.3 billion of equity is available for issuance under the ATM program. See Note 12 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.93 per share in October 2024. 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, issuances of common stock under the ATM program 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 and bank term loans, as a bridge to long-term debt financing. The levels of borrowing may vary significantly due to the timing of long-term debt financings and the impact of fluctuations in cash flows.

	Nine Months Ended September 30,	
	2024	**2023**
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 379.0	$ 556.5
Net Cash Flows from Operating Activities	5,076.9	3,675.7
Net Cash Flows Used for Investing Activities	(4,769.5)	(4,643.5)
Net Cash Flows from (Used for) Financing Activities	(387.2)	818.4
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(79.8)	(149.4)
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 299.2	$ 407.1

Operating Activities

	Nine Months Ended September 30,	
	2024	**2023**
	(in millions)	
Net Income	$ 2,309.9	$ 1,874.8
Non-Cash Adjustments to Net Income (a)	2,540.7	2,469.5
Mark-to-Market of Risk Management Contracts	(97.6)	(82.8)
Property Taxes	508.3	486.1
Deferred Fuel Over/Under-Recovery, Net	304.6	542.8
Change in Other Noncurrent Assets	(244.0)	(396.8)
Change in Other Noncurrent Liabilities	193.8	(21.5)
Change in Certain Components of Working Capital	(438.8)	(1,196.4)
Net Cash Flows from Operating Activities	$ 5,076.9	$ 3,675.7

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Deferred Income Taxes, Loss on the Sale of the Competitive Contracted Renewables Portfolio, Asset Impairments and Other Related Charges and AFUDC.

Net Cash Flows from Operating Activities increased by $1.4 billion primarily due to the following:

- A $758 million increase in cash from the Change in Certain Components of Working Capital. The increase is primarily due to a decrease in fuel, material and supplies driven by lower coal inventory on hand, employee-related benefits and proceeds received from the sale of transferable tax credits. These increases were partially offset by the timing of accounts receivable collections.
- A $506 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.
- A $368 million increase in cash from Change in Other Noncurrent Assets and Change in Other Noncurrent Liabilities. This increase 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.

These increases in cash were partially offset by:

- A $238 million decrease in cash primarily due to the timing of fuel and purchase power related revenues and expenses.

Investing Activities

	Nine Months Ended September 30,	
	2024	2023
	(in millions)	
Construction Expenditures	$ (5,168.6)	$ (5,767.1)
Acquisitions of Nuclear Fuel	(98.4)	(60.9)
Acquisitions of Renewable Energy Facilities	—	(154.0)
Proceeds from Sale of Equity Method Investment	114.0	—
Proceeds from Sales of Assets	365.0	1,335.6
Other	18.5	2.9
Net Cash Flows Used for Investing Activities	$ (4,769.5)	$ (4,643.5)

Net Cash Flows Used for Investing Activities increased by $126 million primarily due to the following:

- A $971 million decrease in Proceeds from Sale of Assets primarily due to the sale of the competitive contracted renewables portfolio in 2023, partially offset by the sale of AEP Onsite Partners in 2024. See "Dispositions" section of Note 6 for additional information.

This decrease in cash was partially offset by:

- A $599 million decrease in Construction Expenditures primarily due to decreases in Vertically Integrated Utilities of $243 million, Transmission and Distribution Utilities of $213 million and AEP Transmission Holdco of $128 million.
- A $146 million increase in cash due to the 2023 acquisition of the Rock Falls Wind Facility. See "Rock Falls Wind Facility" section of Note 6 for additional information.
- A $114 million increase in Proceeds from Sale of Equity Method Investment. See "Disposition of NMRD" section of Note 6 for additional information.

Financing Activities

	Nine Months Ended September 30,	
	2024	2023
	(in millions)	
Issuance of Common Stock	$ 513.0	$ 959.3
Issuance/Retirement of Debt, Net	608.8	1,282.7
Dividends Paid on Common Stock	(1,407.4)	(1,293.8)
Other	(101.6)	(129.8)
Net Cash Flows from (Used for) Financing Activities	$ (387.2)	$ 818.4

Net Cash Flows from (Used for) Financing Activities decreased by $1.2 billion primarily due to the following:

- A $616 million increase in retirements of long-term debt. See Note 12 - Financing Activities for additional information.
- A $446 million decrease in issuances of common stock primarily due to the settlement of equity units in 2023 partially offset by issuances under the ATM program in 2024. See Note 12 - Financing Activities for additional information.
- A $269 million decrease in issuances of long-term debt. See Note 12 - Financing Activities for additional information.

These decreases in cash were partially offset by:

- A $211 million increase due to changes in short-term debt. See Note 12 - Financing Activities for additional information.

See the "Long-term Debt Subsequent Events" section of Note 12 for Long-term debt and other securities issued, retired and principal payments made after September 30, 2024 through November 6, 2024, the date that the third quarter 10-Q was filed.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $8.5 billion of capital expenditures in 2024. For the five year period, 2025 through 2029, management forecasts capital expenditures of $54.4 billion. Management's forecasted capital expenditures for 2025 to 2029 reflect planned increases in investments for transmission infrastructure and new generation resources to support forecasted large load increases and continued improvements in distribution system reliability.

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 strategic sale of assets and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged.

The 2025-2029 estimated capital expenditures by Business Segment are as follows:

Segment	**2025-2029 Budgeted Capital Expenditures**	
	(in millions)	
Vertically Integrated Utilities	$	30,972
Transmission and Distribution Utilities		14,162
AEP Transmission Holdco		8,590
Generation & Marketing		112
Corporate and Other		553
Total	$	54,389

SIGNIFICANT CASH REQUIREMENTS

A summary of significant cash requirements is included in the 2023 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 2023 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 and SEC rulemaking activity.

AROs

AROs are recognized for legal obligations associated with the retirement of property, plant and equipment. When recording an ARO, the present value of the projected liability is recognized in the period in which the legal obligation is incurred or enacted, if a reasonable estimate of fair value can be made. The liability is accreted over time. For operating facilities, the present value of the liability is added to the cost of the associated asset and depreciated over the remaining life of the asset. For retired facilities, the present value of the liability is expensed, and where future recovery through rates is probable, the present value of the liability is subsequently deferred as a regulatory asset. The present value of the initial ARO and subsequent updates are based on discounted cash flows, which include estimates regarding timing of future cash flows, discount rates and cost escalation rates. These estimates are subject to change. Depreciation expense is adjusted prospectively for any changes to the carrying amount of the associated asset.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards and SEC rulemaking activity.

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 Regulatory and Chief Administrative Officer, Executive Vice President Grid Solutions & Government Affairs, Senior Vice President of Regulated Commercial Operations and Senior Vice President of Treasury and Risk. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer, Chief Commercial Officer, Senior Vice President of Treasury and Risk and Senior Vice President of Competitive Commercial Operations. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2023:

MTM Derivative Contract Net Assets (Liabilities)
Nine Months Ended September 30, 2024

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contracts - Commodity Net Assets (Liabilities) as of December 31, 2023	$ 16.9	$ (51.0)	$ 92.4	$ 58.3
Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	1.5	5.2	38.6	45.3
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	(47.1)	(47.1)
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(22.7)	—	46.9	24.2
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	102.3	(6.7)	—	95.6
Total MTM Risk Management Contracts - Commodity Net Assets (Liabilities) as of September 30, 2024	$ 98.0	$ (52.5)	$ 130.8	176.3
Interest Rate MTM Contracts				(9.6)
Commodity Cash Flow Hedge Contracts				94.9
Interest Rate Cash Flow Hedge Contracts				(10.9)
Fair Value Hedge Contracts				(81.7)
Collateral Deposits				(27.6)
Total MTM Derivative Contract Net Assets as of September 30, 2024				$ 141.4

(a) Reflects fair value on primarily auctions or 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 September 30, 2024, credit exposure net of collateral to sub investment grade counterparties was approximately 6.4%, 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 September 30, 2024, 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	$ 590.6	$ 43.4	$ 547.2	3	$ 328.9
Split Rating	10.4	—	10.4	1	10.4
Noninvestment Grade	5.1	—	5.1	2	5.1
No External Ratings:					
Internal Investment Grade	19.6	—	19.6	2	13.2
Internal Noninvestment Grade	81.9	47.3	34.6	2	23.9
Total as of September 30, 2024	$ 707.6	$ 90.7	$ 616.9		

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

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of September 30, 2024, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

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

VaR Model
Trading Portfolio

Nine Months Ended September 30, 2024				Twelve Months Ended December 31, 2023			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.3	$ 1.7	$ 0.3	$ 0.1	$ 0.2	$ 0.9	$ 0.2	$ 0.1

VaR Model
Non-Trading Portfolio

Nine Months Ended September 30, 2024				Twelve Months Ended December 31, 2023			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 15.4	$ 98.6	$ 20.6	$ 7.6	$ 17.7	$ 32.7	$ 16.4	$ 6.1

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. During 2022 and 2023, the Federal Reserve approved 11 rate increases for a cumulative total of 5.25% increase. In light of the progress on inflation and the balance of risks, in September 2024, the Federal Reserve lowered interest rates by 0.50%. AEP has outstanding short and long-term debt which is subject to variable rates. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the nine months ended September 30, 2024 and 2023, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $21 million and $45 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
REVENUES				
Vertically Integrated Utilities	$ 3,248.8	$ 3,158.1	$ 8,722.0	$ 8,603.4
Transmission and Distribution Utilities	1,568.5	1,535.2	4,480.5	4,321.3
Generation & Marketing	483.7	527.5	1,442.1	1,172.6
Other Revenues	119.1	120.9	380.4	307.8
TOTAL REVENUES	5,420.1	5,341.7	15,025.0	14,405.1
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,659.2	1,756.8	4,603.5	4,887.8
Other Operation	805.8	719.9	2,385.4	2,031.1
Maintenance	343.7	325.5	1,012.7	982.8
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	—	—	112.0
Asset Impairments and Other Related Charges	—	—	142.5	—
Depreciation and Amortization	852.7	792.3	2,461.7	2,309.4
Taxes Other Than Income Taxes	407.2	393.9	1,211.2	1,149.2
TOTAL EXPENSES	4,068.6	3,988.4	11,817.0	11,472.3
OPERATING INCOME	1,351.5	1,353.3	3,208.0	2,932.8
Other Income (Expense):				
Other Income	28.5	11.9	55.2	41.0
Allowance for Equity Funds Used During Construction	54.2	51.1	153.0	123.4
Non-Service Cost Components of Net Periodic Benefit Cost	46.5	55.2	129.0	165.9
Interest Expense	(498.8)	(470.3)	(1,400.0)	(1,346.0)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	981.9	1,001.2	2,145.2	1,917.1
Income Tax Expense (Benefit)	37.5	64.2	(97.7)	103.2
Equity Earnings of Unconsolidated Subsidiaries	17.3	21.3	67.0	60.9
NET INCOME	961.7	958.3	2,309.9	1,874.8
Net Income Attributable to Noncontrolling Interests	2.1	4.6	6.9	2.9
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 959.6	$ 953.7	$ 2,303.0	$ 1,871.9
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	532,208,876	520,459,880	529,230,818	516,528,239
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.80	$ 1.83	$ 4.35	$ 3.62
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	533,600,842	521,444,125	530,456,985	517,784,726
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.80	$ 1.83	$ 4.34	$ 3.62

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	**2023**	**2024**	**2023**
Net Income	$ 961.7	$ 958.3	$ 2,309.9	$ 1,874.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(12.3) and $(0.3) for the Three Months Ended September 30, 2024 and 2023, Respectively, and $(8.0) and $(31.5) for the Nine Months Ended September 30, 2024 and 2023, Respectively	(46.3)	(0.9)	(30.1)	(118.5)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.8) for the Three Months Ended September 30, 2024 and 2023, Respectively, and $(0.3) and $(5.9) for the Nine Months Ended September 30, 2024 and 2023, Respectively	(0.6)	(3.2)	(1.3)	(22.4)
Reclassifications of KPCo Pension and OPEB Regulatory Assets, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2024 and 2023, Respectively, and $0 and $4.4 for the Nine Months Ended September 30, 2024 and 2023, Respectively	—	—	—	16.7
TOTAL OTHER COMPREHENSIVE LOSS	(46.9)	(4.1)	(31.4)	(124.2)
TOTAL COMPREHENSIVE INCOME	914.8	954.2	2,278.5	1,750.6
Total Comprehensive Income Attributable To Noncontrolling Interests	2.1	4.6	6.9	2.9
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 912.7	$ 949.6	$ 2,271.6	$ 1,747.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2024 and 2023
(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, 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) (a)		(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) (a)		(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
Issuance of Common Stock	0.4	2.8	878.9				881.7
Common Stock Dividends				(429.7) (a)		(0.5)	(430.2)
Other Changes in Equity			6.7				6.7
Disposition of Competitive Contracted Renewables Portfolio						(186.4)	(186.4)
Net Income				953.7		4.6	958.3
Other Comprehensive Loss					(4.1)		(4.1)
TOTAL EQUITY – SEPTEMBER 30, 2023	526.8	$ 3,424.3	$ 8,996.4	$ 12,929.5	$ (40.5)	$ 39.9	$ 25,349.6
TOTAL EQUITY – DECEMBER 31, 2023	527.4	$ 3,427.9	$ 9,073.9	$ 12,800.4	$ (55.5)	$ 39.2	$ 25,285.9
Issuance of Common Stock	0.8	5.4	35.2				40.6
Common Stock Dividends				(465.5) (b)		(1.4)	(466.9)
Other Changes in Equity			(14.8)				(14.8)
Net Income				1,003.1		2.6	1,005.7
Other Comprehensive Loss					(6.8)		(6.8)
TOTAL EQUITY – MARCH 31, 2024	528.2	3,433.3	9,094.3	13,338.0	(62.3)	40.4	25,843.7
Issuance of Common Stock	4.9	32.1	403.1				435.2
Common Stock Dividends				(467.0) (b)		(2.1)	(469.1)
Other Changes in Equity			1.1				1.1
Net Income				340.3		2.2	342.5
Other Comprehensive Income					22.3		22.3
TOTAL EQUITY – JUNE 30, 2024	533.1	3,465.4	9,498.5	13,211.3	(40.0)	40.5	26,175.7
Issuance of Common Stock	0.6	3.3	33.9				37.2
Common Stock Dividends				(470.2) (b)		(1.2)	(471.4)
Other Changes in Equity			2.5				2.5
Net Income				959.6		2.1	961.7
Other Comprehensive Loss					(46.9)		(46.9)
TOTAL EQUITY – SEPTEMBER 30, 2024	533.7	$ 3,468.7	$ 9,534.9	$ 13,700.7	$ (86.9)	$ 41.4	$ 26,658.8

(a) Cash dividends declared per AEP common share were $0.83.
(b) Cash dividends declared per AEP common share were $0.88.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2024 and December 31, 2023
(in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 245.8	$ 330.1
Restricted Cash (September 30, 2024 and December 31, 2023 Amounts Include $53.4 and $48.9, Respectively, Related to Transition Funding, Restoration Funding and Appalachian Consumer Rate Relief Funding)	53.4	48.9
Other Temporary Investments (September 30, 2024 and December 31, 2023 Amounts Include $216.3 and $205, Respectively, Related to EIS and Transource Energy)	228.6	214.3
Accounts Receivable:		
Customers	963.6	1,029.9
Accrued Unbilled Revenues	303.2	179.5
Pledged Accounts Receivable – AEP Credit	1,330.3	1,249.4
Miscellaneous	65.4	48.7
Allowance for Uncollectible Accounts	(65.4)	(60.1)
Total Accounts Receivable	2,597.1	2,447.4
Fuel	704.0	853.7
Materials and Supplies	981.7	1,025.8
Risk Management Assets	236.7	217.5
Accrued Tax Benefits	125.4	156.2
Regulatory Asset for Under-Recovered Fuel Costs	399.7	514.0
Prepayments and Other Current Assets	448.4	274.2
TOTAL CURRENT ASSETS	6,020.8	6,082.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,504.5	24,329.5
Transmission	37,309.8	35,934.1
Distribution	30,486.1	28,989.9
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	6,829.2	6,484.9
Construction Work in Progress	6,797.0	5,508.0
Total Property, Plant and Equipment	105,926.6	101,246.4
Accumulated Depreciation and Amortization	25,852.8	24,553.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	80,073.8	76,693.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,318.9	5,092.4
Securitized Assets	253.4	336.3
Spent Nuclear Fuel and Decommissioning Trusts	4,425.8	3,860.2
Goodwill	52.5	52.5
Long-term Risk Management Assets	258.3	321.2
Operating Lease Assets	572.9	620.2
Deferred Charges and Other Noncurrent Assets	3,142.7	3,625.7
TOTAL OTHER NONCURRENT ASSETS	14,024.5	13,908.5
TOTAL ASSETS	$ 100,119.1	$ 96,684.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2024 and December 31, 2023
(in millions, except per-share and share amounts)
(Unaudited)

			September 30, 2024	December 31, 2023
CURRENT LIABILITIES				
Accounts Payable			$ 2,265.6	$ 2,032.5
Short-term Debt:				
Securitized Debt for Receivables – AEP Credit			900.0	888.0
Other Short-term Debt			759.6	1,942.2
Total Short-term Debt			1,659.6	2,830.2
Long-term Debt Due Within One Year (September 30, 2024 and December 31, 2023 Amounts Include $190.7 and $207.2, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			2,826.7	2,490.5
Risk Management Liabilities			152.0	229.6
Customer Deposits			410.6	423.7
Accrued Taxes			1,236.6	1,800.1
Accrued Interest			584.4	410.2
Obligations Under Operating Leases			96.7	115.7
Other Current Liabilities			1,415.4	1,251.1
TOTAL CURRENT LIABILITIES			10,647.6	11,583.6
NONCURRENT LIABILITIES				
Long-term Debt (September 30, 2024 and December 31, 2023 Amounts Include $545.9 and $556.3, Respectively, Related to Sabine, DCC Fuel, Transition Funding, Restoration Funding, Appalachian Consumer Rate Relief Funding and Transource Energy)			39,147.7	37,652.7
Long-term Risk Management Liabilities			201.6	241.8
Deferred Income Taxes			9,958.8	9,415.7
Regulatory Liabilities and Deferred Investment Tax Credits			8,366.2	8,182.4
Asset Retirement Obligations			3,687.7	2,972.5
Employee Benefits and Pension Obligations			216.5	241.7
Obligations Under Operating Leases			490.5	519.4
Deferred Credits and Other Noncurrent Liabilities			677.9	545.8
TOTAL NONCURRENT LIABILITIES			62,746.9	59,772.0
TOTAL LIABILITIES			73,394.5	71,355.6
Rate Matters (Note 4)				
Commitments and Contingencies (Note 5)				
MEZZANINE EQUITY				
Contingently Redeemable Performance Share Awards			65.8	42.5
TOTAL MEZZANINE EQUITY			65.8	42.5
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2024	2023		
Shares Authorized	600,000,000	600,000,000		
Shares Issued	533,652,728	527,369,157		
(1,184,572 Shares were Held in Treasury as of September 30, 2024 and December 31, 2023, Respectively)			3,468.7	3,427.9
Paid-in Capital			9,534.9	9,073.9
Retained Earnings			13,700.7	12,800.4
Accumulated Other Comprehensive Income (Loss)			(86.9)	(55.5)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			26,617.4	25,246.7
Noncontrolling Interests			41.4	39.2
TOTAL EQUITY			26,658.8	25,285.9
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY			$ 100,119.1	$ 96,684.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
OPERATING ACTIVITIES		
Net Income	$ 2,309.9	$ 1,874.8
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	2,461.7	2,309.4
Deferred Income Taxes	89.5	171.5
Loss on the Sale of the Competitive Contracted Renewables Portfolio	—	112.0
Asset Impairments and Other Related Charges	142.5	—
Allowance for Equity Funds Used During Construction	(153.0)	(123.4)
Mark-to-Market of Risk Management Contracts	(97.6)	(82.8)
Property Taxes	508.3	486.1
Deferred Fuel Over/Under-Recovery, Net	304.6	542.8
Change in Other Noncurrent Assets	(244.0)	(396.8)
Change in Other Noncurrent Liabilities	193.8	(21.5)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(131.8)	114.0
Fuel, Materials and Supplies	188.5	(344.4)
Accounts Payable	14.2	(163.0)
Accrued Taxes, Net	(532.3)	(566.7)
Other Current Assets	(139.2)	(91.5)
Other Current Liabilities	161.8	(144.8)
Net Cash Flows from Operating Activities	5,076.9	3,675.7
INVESTING ACTIVITIES		
Construction Expenditures	(5,168.6)	(5,767.1)
Purchases of Investment Securities	(2,398.0)	(2,199.7)
Sales of Investment Securities	2,343.5	2,140.1
Acquisitions of Nuclear Fuel	(98.4)	(60.9)
Acquisitions of Renewable Energy Facilities	—	(154.0)
Proceeds from Sales of Assets	365.0	1,335.6
Proceeds from Sale of Equity Method Investment	114.0	—
Other Investing Activities	73.0	62.5
Net Cash Flows Used for Investing Activities	(4,769.5)	(4,643.5)
FINANCING ACTIVITIES		
Issuance of Common Stock	513.0	959.3
Issuance of Long-term Debt	3,748.5	4,017.8
Issuance of Short-term Debt with Original Maturities greater than 90 Days	376.6	791.7
Change in Short-term Debt with Original Maturities less than 90 Days, Net	(676.1)	(1,044.7)
Retirement of Long-term Debt	(1,969.1)	(1,353.3)
Redemption of Short-term Debt with Original Maturities Greater than 90 Days	(871.1)	(1,128.8)
Principal Payments for Finance Lease Obligations	(51.2)	(53.9)
Dividends Paid on Common Stock	(1,407.4)	(1,293.8)
Other Financing Activities	(50.4)	(75.9)
Net Cash Flows from (Used for) Financing Activities	(387.2)	818.4
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(79.8)	(149.4)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	379.0	556.5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 299.2	$ 407.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TEXAS INC. 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 September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in millions of KWhs)			
Retail:				
Residential	4,116	4,681	10,174	10,295
Commercial	4,283	4,021	11,733	10,208
Industrial	3,181	3,065	9,778	9,344
Miscellaneous	189	196	496	487
Total Retail	11,769	11,963	32,181	30,334

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in degree days)			
Actual – Heating (a)	—	—	162	143
Normal – Heating (b)	—	—	198	197
Actual – Cooling (c)	1,457	1,719	2,801	2,945
Normal – Cooling (b)	1,401	1,387	2,487	2,454

(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 2023 to 2024 Net Income
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Net Income	$ 125.5	$ 282.2
Changes in Revenues:		
Retail Revenues	5.2	84.9
Transmission Revenues	16.1	47.3
Other Revenues	(4.7)	(0.3)
Total Change in Revenues	16.6	131.9
Changes in Expenses and Other:		
Other Operation and Maintenance	(7.8)	(48.7)
Depreciation and Amortization	(1.1)	(16.8)
Taxes Other Than Income Taxes	3.8	11.5
Interest Income	2.6	4.2
Allowance for Equity Funds Used During Construction	2.7	15.2
Non-Service Cost Components of Net Periodic Benefit Cost	(1.1)	(3.6)
Interest Expense	(7.8)	(15.4)
Total Change in Expenses and Other	(8.7)	(53.6)
Income Tax Expense	(0.9)	(19.9)
2024 Net Income	$ 132.5	$ 340.6

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Retail Revenues** increased $5 million primarily due to the following:
  - A $25 million increase in revenue from rate riders.

  This increase was partially offset by:
  - A $12 million decrease in weather-related usage primarily due to a 15% decrease in cooling degree days.
  - An $8 million decrease in weather-normalized revenues primarily in the residential class.
- **Transmission Revenues** increased $16 million due to the following:
  - A $10 million increase in interim rates driven by increased transmission investments.
  - A $6 million increase due to increased load.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $8 million primarily due to the following:
  - A $4 million increase in distribution-related expenses.
  - A $4 million increase in employee-related expenses.
- **Interest Expense** increased $8 million primarily due to higher debt balances and interest rates.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Retail Revenues** increased $85 million primarily due to the following:
  - A $73 million increase in revenue from rate riders.
  - A $21 million increase in weather-normalized revenues primarily in the commercial and residential classes.

  These increases were partially offset by:
  - A $10 million decrease in weather-related usage primarily due to a 5% decrease in cooling degree days.
- **Transmission Revenues** increased $47 million due to the following:
  - A $29 million increase in interim rates driven by increased transmission investments.
  - An $18 million increase due to increased load.

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

- **Other Operation and Maintenance** expenses increased $49 million primarily due to the following:
  - A $28 million increase due to a prior year decrease in expenses driven by legislation passed in Texas in May 2023 allowing employee financially based incentives to be recovered.
  - A $20 million increase in employee-related expenses due to the voluntary severance program.
- **Depreciation and Amortization** expenses increased $17 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** decreased $12 million primarily due to lower property taxes driven by decreased tax rates.
- **Allowance for Equity Funds Used During Construction** increased $15 million primarily due to a higher AFUDC base.
- **Interest Expense** increased $15 million primarily due to the following:
  - A $21 million increase due to higher debt balances and interest rates.

  This increase was partially offset by:
  - A $6 million decrease due to an increase of capitalization of AFUDC on prepaid pension and OPEB.
- **Income Tax Expense** increased $20 million primarily due to the following:
  - A $16 million increase due to an increase in pretax book income.
  - A $6 million increase due to a decrease in amortization of Excess ADIT.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
REVENUES				
Electric Transmission and Distribution	$ 569.2	$ 551.6	$ 1,569.9	$ 1,438.7
Sales to AEP Affiliates	1.3	1.2	4.0	3.7
Other Revenues	0.7	1.8	3.3	2.9
TOTAL REVENUES	571.2	554.6	1,577.2	1,445.3
EXPENSES				
Other Operation	164.7	154.4	453.3	395.2
Maintenance	22.5	25.0	66.3	75.7
Depreciation and Amortization	126.7	125.6	368.3	351.5
Taxes Other Than Income Taxes	44.8	48.6	125.4	136.9
TOTAL EXPENSES	358.7	353.6	1,013.3	959.3
OPERATING INCOME	212.5	201.0	563.9	486.0
Other Income (Expense):				
Interest Income	3.1	0.5	5.7	1.5
Allowance for Equity Funds Used During Construction	10.5	7.8	34.6	19.4
Non-Service Cost Components of Net Periodic Benefit Cost	3.7	4.8	10.8	14.4
Interest Expense	(67.7)	(59.9)	(188.5)	(173.1)
INCOME BEFORE INCOME TAX EXPENSE	162.1	154.2	426.5	348.2
Income Tax Expense	29.6	28.7	85.9	66.0
NET INCOME	$ 132.5	$ 125.5	$ 340.6	$ 282.2

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
Net Income	$ 132.5	$ 125.5	$ 340.6	$ 282.2
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2024 and 2023, Respectively, and $1.6 and $0.8 for the Nine Months Ended September 30, 2024 and 2023, Respectively	(0.1)	(0.1)	6.0	3.1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2024 and 2023, Respectively, and $0 and $(0.1) for the Nine Months Ended September 30, 2024 and 2023, Respectively	—	—	—	(0.6)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(0.1)	(0.1)	6.0	2.5
TOTAL COMPREHENSIVE INCOME	$ 132.4	$ 125.4	$ 346.6	$ 284.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
Capital Contribution from Parent	250.5			250.5
Net Income		125.5		125.5
Other Comprehensive Loss			(0.1)	(0.1)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2023	$ 2,079.7	$ 2,636.9	$ (6.1)	$ 4,710.5
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	$ 2,079.6	$ 2,725.1	$ (8.6)	$ 4,796.1
Net Income		79.7		79.7
Other Comprehensive Income			3.9	3.9
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2024	2,079.6	2,804.8	(4.7)	4,879.7
Capital Contribution from Parent	1.6			1.6
Net Income		128.4		128.4
Other Comprehensive Income			2.2	2.2
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2024	2,081.2	2,933.2	(2.5)	5,011.9
Return of Capital to Parent	(0.7)			(0.7)
Common Stock Dividends		(150.0)		(150.0)
Net Income		132.5		132.5
Other Comprehensive Loss			(0.1)	(0.1)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2024	$ 2,080.5	$ 2,915.7	$ (2.6)	$ 4,993.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2024 and December 31, 2023
(in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 0.1	$ 0.1
Restricted Cash (September 30, 2024 and December 31, 2023 Amounts Include $45.1 and $34, Respectively, Related to Transition Funding and Restoration Funding)	45.1	34.0
Advances to Affiliates	61.8	7.1
Accounts Receivable:		
Customers	213.0	176.5
Affiliated Companies	20.4	23.8
Accrued Unbilled Revenues	116.7	82.3
Miscellaneous	0.3	0.8
Allowance for Uncollectible Accounts	(4.1)	(4.9)
Total Accounts Receivable	346.3	278.5
Materials and Supplies	178.6	190.4
Insurance Receivable	55.0	—
Prepayments and Other Current Assets	17.5	10.0
TOTAL CURRENT ASSETS	704.4	520.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	7,180.8	6,812.6
Distribution	6,157.0	5,798.8
Other Property, Plant and Equipment	1,172.2	1,145.9
Construction Work in Progress	1,159.0	904.6
Total Property, Plant and Equipment	15,669.0	14,661.9
Accumulated Depreciation and Amortization	2,018.2	1,887.9
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	13,650.8	12,774.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	354.0	315.3
Securitized Assets (September 30, 2024 and December 31, 2023 Amounts Include $140.4 and $202.9, Respectively, Related to Transition Funding and Restoration Funding)	140.4	202.9
Deferred Charges and Other Noncurrent Assets	195.5	178.4
TOTAL OTHER NONCURRENT ASSETS	689.9	696.6
TOTAL ASSETS	$ 15,045.1	$ 13,990.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2024 and December 31, 2023
(in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 103.7
Accounts Payable:		
General	273.5	192.3
Affiliated Companies	29.3	27.7
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2024 and December 31, 2023 Amounts Include $63.9 and $95.9, Respectively, Related to Transition Funding and Restoration Funding)	113.9	96.0
Accrued Taxes	152.9	99.1
Accrued Interest (September 30, 2024 and December 31, 2023 Amounts Include $1.4 and $2, Respectively, Related to Transition Funding and Restoration Funding)	97.1	49.2
Obligations Under Operating Leases	16.1	28.7
Accrued Litigation Settlement	55.0	—
Other Current Liabilities	193.3	152.7
TOTAL CURRENT LIABILITIES	931.1	749.4
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (September 30, 2024 and December 31, 2023 Amounts Include $102.1 and $125.9, Respectively, Related to Transition Funding and Restoration Funding)	6,365.5	5,793.8
Deferred Income Taxes	1,306.6	1,227.8
Regulatory Liabilities and Deferred Investment Tax Credits	1,283.0	1,261.4
Obligations Under Operating Leases	45.9	50.9
Deferred Credits and Other Noncurrent Liabilities	119.4	111.3
TOTAL NONCURRENT LIABILITIES	9,120.4	8,445.2
TOTAL LIABILITIES	10,051.5	9,194.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	2,080.5	2,079.6
Retained Earnings	2,915.7	2,725.1
Accumulated Other Comprehensive Income (Loss)	(2.6)	(8.6)
TOTAL COMMON SHAREHOLDER'S EQUITY	4,993.6	4,796.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 15,045.1	$ 13,990.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2024	2023
OPERATING ACTIVITIES		
Net Income	$ 340.6	$ 282.2
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	368.3	351.5
Deferred Income Taxes	70.3	64.2
Allowance for Equity Funds Used During Construction	(34.6)	(19.4)
Change in Other Noncurrent Assets	(99.3)	(118.0)
Change in Other Noncurrent Liabilities	32.0	26.7
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(67.8)	(81.8)
Materials and Supplies	11.8	(32.1)
Accounts Payable	23.6	0.7
Accrued Taxes, Net	56.0	39.7
Other Current Assets	(9.1)	(0.7)
Other Current Liabilities	43.8	(9.9)
Net Cash Flows from Operating Activities	735.6	503.1
INVESTING ACTIVITIES		
Construction Expenditures	(1,042.4)	(1,175.1)
Change in Advances to Affiliates, Net	(54.7)	(42.1)
Other Investing Activities	44.2	42.2
Net Cash Flows Used for Investing Activities	(1,052.9)	(1,175.0)
FINANCING ACTIVITIES		
Capital Contribution from Parent	1.6	525.8
Return of Capital to Parent	(0.7)	(4.3)
Issuance of Long-term Debt – Nonaffiliated	841.9	505.4
Change in Advances from Affiliates, Net	(103.7)	(96.5)
Retirement of Long-term Debt – Nonaffiliated	(256.5)	(240.0)
Principal Payments for Finance Lease Obligations	(5.6)	(5.5)
Dividends Paid on Common Stock	(150.0)	—
Other Financing Activities	1.4	1.2
Net Cash Flows from Financing Activities	328.4	686.1
Net Increase in Cash, Cash Equivalents and Restricted Cash	11.1	14.2
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	34.1	32.8
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 45.2	$ 47.0
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 132.8	$ 135.9
Net Cash Paid (Received) for Income Taxes	(2.7)	4.3
Noncash Acquisitions Under Finance Leases	3.6	3.7
Construction Expenditures Included in Current Liabilities as of September 30,	167.3	153.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of September 30, 2024	As of September 30, 2023
	(in millions)	
Plant In Service	$ 14,720.4	$ 13,638.0
Construction Work in Progress	2,188.6	1,902.1
Accumulated Depreciation and Amortization	1,509.4	1,221.2
Total Transmission Property, Net	$ 15,399.6	$ 14,318.9

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of 2023 to 2024 Net Income
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Net Income	$ 179.2	$ 517.6
Changes in Transmission Revenues:		
Transmission Revenues	34.5	106.0
Total Change in Transmission Revenues	34.5	106.0
Changes in Expenses and Other:		
Other Operation and Maintenance	(0.7)	(16.3)
Depreciation and Amortization	(8.6)	(29.6)
Taxes Other Than Income Taxes	(5.9)	(12.0)
Interest Income	1.5	3.6
Allowance for Equity Funds Used During Construction	1.6	2.5
Interest Expense	(2.7)	(13.0)
Total Change in Expenses and Other	(14.8)	(64.8)
Income Tax Expense	(7.6)	(10.6)
2024 Net Income	$ 191.3	$ 548.2

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Transmission Revenues** increased $35 million primarily due to continued investment in transmission assets.

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

- **Depreciation and Amortization** expenses increased $9 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to higher property taxes driven by increased transmission investment.
- **Income Tax Expense** increased $8 million primarily due to an increase in pretax book income and an increase in state income taxes.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Transmission Revenues** increased $106 million primarily due to continued investment in transmission assets.

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

- **Other Operation and Maintenance** expenses increased $16 million primarily due to a $12 million increase in employee-related expenses driven by an $11 million increase associated with the voluntary severance program.
- **Depreciation and Amortization** expenses increased $30 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $12 million primarily due to higher property taxes driven by increased transmission investment.
- **Interest Expense** increased $13 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $11 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 Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
REVENUES				
Transmission Revenues	$ 103.3	$ 93.8	$ 299.0	$ 274.0
Sales to AEP Affiliates	404.4	374.7	1,188.2	1,097.9
Provision for Refund – Affiliated	(8.5)	(4.8)	(31.1)	(17.9)
Provision for Refund – Nonaffiliated	(2.2)	(1.0)	(3.9)	(4.8)
Other Revenues	0.2	—	3.0	—
TOTAL REVENUES	497.2	462.7	1,455.2	1,349.2
EXPENSES				
Other Operation	31.7	31.6	101.6	87.0
Maintenance	5.7	5.1	16.0	14.3
Depreciation and Amortization	108.2	99.6	320.8	291.2
Taxes Other Than Income Taxes	79.7	73.8	228.6	216.6
TOTAL EXPENSES	225.3	210.1	667.0	609.1
OPERATING INCOME	271.9	252.6	788.2	740.1
Other Income (Expense):				
Interest Income – Affiliated	3.1	1.6	9.3	5.7
Allowance for Equity Funds Used During Construction	24.3	22.7	64.7	62.2
Interest Expense	(54.3)	(51.6)	(160.5)	(147.5)
INCOME BEFORE INCOME TAX EXPENSE	245.0	225.3	701.7	660.5
Income Tax Expense	53.7	46.1	153.5	142.9
NET INCOME	$ 191.3	$ 179.2	$ 548.2	$ 517.6

AEPTCo is wholly-owned by AEP Transmission Holdco.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Total
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
Capital Contribution from Member	2.9		2.9
Dividends Paid to Member		(30.0)	(30.0)
Net Income		179.2	179.2
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2023	$ 3,041.6	$ 3,253.3	$ 6,294.9
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2023	$ 3,043.4	$ 3,289.9	$ 6,333.3
Capital Contribution from Member	25.0		25.0
Dividends Paid to Member		(40.0)	(40.0)
Net Income		181.2	181.2
TOTAL MEMBER'S EQUITY – MARCH 31, 2024	3,068.4	3,431.1	6,499.5
Capital Contribution from Member	9.6		9.6
Dividends Paid to Member		(31.0)	(31.0)
Net Income		175.7	175.7
TOTAL MEMBER'S EQUITY – JUNE 30, 2024	3,078.0	3,575.8	6,653.8
Return of Capital to Member	(4.5)		(4.5)
Dividends Paid to Member		(26.0)	(26.0)
Net Income		191.3	191.3
TOTAL MEMBER'S EQUITY – SEPTEMBER 30, 2024	$ 3,073.5	$ 3,741.1	$ 6,814.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2024 and December 31, 2023
(in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT ASSETS		
Advances to Affiliates	$ 181.8	$ 67.1
Accounts Receivable:		
Customers	61.2	82.2
Affiliated Companies	141.1	125.5
Total Accounts Receivable	202.3	207.7
Prepayments and Other Current Assets	12.5	4.0
TOTAL CURRENT ASSETS	396.6	278.8
TRANSMISSION PROPERTY		
Transmission Property	14,209.3	13,723.9
Other Property, Plant and Equipment	511.1	501.4
Construction Work in Progress	2,188.6	1,563.7
Total Transmission Property	16,909.0	15,789.0
Accumulated Depreciation and Amortization	1,509.4	1,291.3
TOTAL TRANSMISSION PROPERTY – NET	15,399.6	14,497.7
OTHER NONCURRENT ASSETS		
Regulatory Assets	0.9	3.1
Deferred Property Taxes	90.1	286.4
Deferred Charges and Other Noncurrent Assets	7.1	6.5
TOTAL OTHER NONCURRENT ASSETS	98.1	296.0
TOTAL ASSETS	$ 15,894.3	$ 15,072.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
September 30, 2024 and December 31, 2023
(Unaudited)

	September 30, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 42.8	$ 174.3
Accounts Payable:		
General	322.5	274.7
Affiliated Companies	94.8	107.9
Long-term Debt Due Within One Year – Nonaffiliated	185.0	95.0
Accrued Taxes	418.9	568.6
Accrued Interest	68.4	39.6
Obligations Under Operating Leases	1.2	1.3
Other Current Liabilities	21.9	24.7
TOTAL CURRENT LIABILITIES	1,155.5	1,286.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	5,677.3	5,319.4
Deferred Income Taxes	1,236.9	1,147.7
Regulatory Liabilities	857.1	783.7
Obligations Under Operating Leases	1.1	1.4
Deferred Credits and Other Noncurrent Liabilities	151.8	200.9
TOTAL NONCURRENT LIABILITIES	7,924.2	7,453.1
TOTAL LIABILITIES	9,079.7	8,739.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	3,073.5	3,043.4
Retained Earnings	3,741.1	3,289.9
TOTAL MEMBER'S EQUITY	6,814.6	6,333.3
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 15,894.3	$ 15,072.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2024	2023
OPERATING ACTIVITIES		
Net Income	$ 548.2	$ 517.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	320.8	291.2
Deferred Income Taxes	75.7	64.2
Allowance for Equity Funds Used During Construction	(64.7)	(62.2)
Property Taxes	196.3	184.4
Change in Other Noncurrent Assets	0.8	5.8
Change in Other Noncurrent Liabilities	(40.1)	7.7
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5.4	(37.1)
Materials and Supplies	—	10.4
Accounts Payable	(16.1)	25.0
Accrued Taxes, Net	(149.9)	(202.2)
Other Current Assets	(1.9)	(1.0)
Other Current Liabilities	22.2	21.7
Net Cash Flows from Operating Activities	896.7	825.5
INVESTING ACTIVITIES		
Construction Expenditures	(1,042.9)	(1,224.9)
Change in Advances to Affiliates, Net	(114.7)	(86.2)
Other Investing Activities	13.6	4.8
Net Cash Flows Used for Investing Activities	(1,144.0)	(1,306.3)
FINANCING ACTIVITIES		
Capital Contribution from Member	34.6	27.9
Return of Capital to Member	(4.5)	(8.6)
Issuance of Long-term Debt – Nonaffiliated	445.7	689.0
Change in Advances from Affiliates, Net	(131.5)	(112.5)
Dividends Paid to Member	(97.0)	(115.0)
Net Cash Flows from Financing Activities	247.3	480.8
Net Change in Cash and Cash Equivalents	—	—
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 128.0	$ 116.9
Net Cash Paid for Income Taxes	5.7	55.0
Construction Expenditures Included in Current Liabilities as of September 30,	221.3	219.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

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 September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in millions of KWhs)			
Retail:				
Residential	2,568	2,481	7,918	7,527
Commercial	1,553	1,537	4,482	4,286
Industrial	2,141	2,229	6,446	6,473
Miscellaneous	203	205	617	595
Total Retail	6,465	6,452	19,463	18,881
Wholesale (a)	550	691	1,768	1,694
Total KWhs	7,015	7,143	21,231	20,575

(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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in degree days)			
Actual – Heating (a)	—	—	1,029	928
Normal – Heating (b)	2	2	1,397	1,410
Actual – Cooling (c)	962	873	1,499	1,106
Normal – Cooling (b)	837	837	1,221	1,222

(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 2023 to 2024 Net Income
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Net Income	$ 91.9	$ 247.3
Changes in Revenues:		
Retail Revenues	65.5	244.0
Off-system Sales	(0.8)	(1.1)
Transmission Revenues	0.7	1.8
Other Revenues	1.7	11.4
Total Change in Revenues	67.1	256.1
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(15.2)	(99.2)
Other Operation and Maintenance	(28.4)	(81.4)
Depreciation and Amortization	(5.3)	(19.7)
Taxes Other Than Income Taxes	(0.8)	(6.0)
Interest Income	1.0	1.6
Allowance for Equity Funds Used During Construction	0.6	2.7
Non-Service Cost Components of Net Periodic Benefit Cost	(1.2)	(4.0)
Interest Expense	1.3	(2.7)
Total Change in Expenses and Other	(48.0)	(208.7)
Income Tax Expense	(1.2)	9.9
2024 Net Income	$ 109.8	$ 304.6

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Retail Revenues** increased $66 million primarily due to the following:
  - A $28 million increase in rider revenues.
  - A $23 million increase in rates due to the 2020-2022 Virginia Triennial Review.
  - A $7 million increase in weather-related usage driven by a 10% increase in cooling degree days.
  - A $6 million increase in fuel revenues.

Expenses and Other changed between years as follows:

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $15 million primarily due to expensing of past under-recovered fuel deferrals in West Virginia to correspond with recovery of those deferrals in ENEC rates.
- **Other Operation and Maintenance** expenses increased $28 million primarily due to the following:
  - A $13 million increase due to prior year proceeds received for insurance policy settlements.
  - An $11 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $7 million increase in distribution expenses primarily due to an increase in vegetation management costs.

  These increases were partially offset by:
  - A $7 million decrease due to the January 2024 completion of regulatory asset amortization related to under-earnings during the 2017-2019 Triennial Review.
- **Depreciation and Amortization** expenses increased $5 million primarily due to a higher depreciable base.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Retail Revenues** increased $244 million primarily due to the following:
  - An $88 million increase in rider revenues.
  - A $60 million increase in rates due to the 2020-2022 Virginia Triennial Review.
  - A $57 million increase in fuel revenues.
  - A $47 million increase in weather-related usage driven by a 36% increase in cooling degree days and an 11% increase in heating degree days.
- **Other Revenues** increased $11 million primarily due to pole attachment revenue.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $99 million primarily due to expensing of past under-recovered fuel deferrals in West Virginia to correspond with recovery of those deferrals in ENEC rates, increased non-recoverable wind purchases and the amortization of Excess ADIT through the ENEC.
- **Other Operation and Maintenance** expenses increased $81 million primarily due to the following:
  - A $49 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $26 million increase in employee-related expenses due to the voluntary severance program.
  - A $16 million increase in distribution expenses primarily due to an increase in vegetation management costs.
  - A $13 million increase due to prior year proceeds received for insurance policy settlements.

  These increases were partially offset by:
  - A $19 million decrease due to the January 2024 completion of regulatory asset amortization related to under-earnings during the 2017-2019 Triennial Review.
- **Depreciation and Amortization** expenses increased $20 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $6 million due to an increase in Virginia state minimum taxes.
- **Income Tax Expense** decreased $10 million primarily due to an increase in amortization of Excess ADIT.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	**2023**	**2024**	**2023**
REVENUES				
Electric Generation, Transmission and Distribution	$ 960.6	$ 896.0	$ 2,836.6	$ 2,573.0
Sales to AEP Affiliates	65.2	62.5	183.1	193.2
Other Revenues	3.1	3.3	12.4	9.8
TOTAL REVENUES	1,028.9	961.8	3,032.1	2,776.0
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	358.4	343.2	1,060.0	960.8
Other Operation	204.2	187.9	628.8	569.6
Maintenance	86.4	74.3	244.7	222.5
Depreciation and Amortization	149.0	143.7	444.5	424.8
Taxes Other Than Income Taxes	44.3	43.5	132.5	126.5
TOTAL EXPENSES	842.3	792.6	2,510.5	2,304.2
OPERATING INCOME	186.6	169.2	521.6	471.8
Other Income (Expense):				
Interest Income	1.8	0.8	3.8	2.2
Allowance for Equity Funds Used During Construction	4.2	3.6	11.4	8.7
Non-Service Cost Components of Net Periodic Benefit Cost	6.9	8.1	20.4	24.4
Interest Expense	(67.2)	(68.5)	(203.4)	(200.7)
INCOME BEFORE INCOME TAX EXPENSE	132.3	113.2	353.8	306.4
Income Tax Expense	22.5	21.3	49.2	59.1
NET INCOME	$ 109.8	$ 91.9	$ 304.6	$ 247.3

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	**2023**	**2024**	**2023**
Net Income	$ 109.8	$ 91.9	$ 304.6	$ 247.3
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2024 and 2023, Respectively, and $(0.2) and $(0.2) for the Nine Months Ended September 30, 2024 and 2023, Respectively	(0.2)	(0.2)	(0.6)	(0.6)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.2) for the Three Months Ended September 30, 2024 and 2023, Respectively, and $(0.2) and $(0.6) for the Nine Months Ended September 30, 2024 and 2023, Respectively	(0.2)	(0.7)	(0.8)	(2.3)
TOTAL OTHER COMPREHENSIVE LOSS	(0.4)	(0.9)	(1.4)	(2.9)
TOTAL COMPREHENSIVE INCOME	$ 109.4	$ 91.0	$ 303.2	$ 244.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
Capital Contribution from Parent		2.2			2.2
Net Income			91.9		91.9
Other Comprehensive Loss				(0.9)	(0.9)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2023	$ 260.4	$ 1,835.2	$ 3,138.4	$ (7.7)	$ 5,226.3
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2023	$ 260.4	$ 1,834.5	$ 3,185.5	$ (3.7)	$ 5,276.7
Capital Contribution from Parent		100.0			100.0
Net Income			136.5		136.5
Other Comprehensive Loss				(0.5)	(0.5)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2024	260.4	1,934.5	3,322.0	(4.2)	5,512.7
Capital Contribution from Parent		9.5			9.5
Net Income			58.3		58.3
Other Comprehensive Loss				(0.5)	(0.5)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2024	260.4	1,944.0	3,380.3	(4.7)	5,580.0
Return of Capital to Parent		(4.5)			(4.5)
Common Stock Dividends			(75.0)		(75.0)
Net Income			109.8		109.8
Other Comprehensive Loss				(0.4)	(0.4)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2024	$ 260.4	$ 1,939.5	$ 3,415.1	$ (5.1)	$ 5,609.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2024 and December 31, 2023
(in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6.5	$ 5.0
Restricted Cash for Securitized Funding	8.3	14.9
Advances to Affiliates	18.9	18.9
Accounts Receivable:		
Customers	183.0	170.3
Affiliated Companies	102.7	98.8
Accrued Unbilled Revenues	53.3	70.8
Miscellaneous	0.2	0.6
Allowance for Uncollectible Accounts	(2.0)	(2.0)
Total Accounts Receivable	337.2	338.5
Fuel	270.3	315.0
Materials and Supplies	130.9	148.4
Risk Management Assets	47.1	22.4
Regulatory Asset for Under-Recovered Fuel Costs	153.7	155.4
Prepayments and Other Current Assets	64.8	40.5
TOTAL CURRENT ASSETS	1,037.7	1,059.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	7,245.9	7,041.3
Transmission	4,912.9	4,711.8
Distribution	5,412.0	5,176.6
Other Property, Plant and Equipment	1,046.4	981.3
Construction Work in Progress	752.5	709.2
Total Property, Plant and Equipment	19,369.7	18,620.2
Accumulated Depreciation and Amortization	5,964.9	5,688.7
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	13,404.8	12,931.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,312.4	1,155.1
Securitized Assets	113.0	133.4
Employee Benefits and Pension Assets	184.8	171.7
Operating Lease Assets	70.2	73.7
Deferred Charges and Other Noncurrent Assets	166.5	187.5
TOTAL OTHER NONCURRENT ASSETS	1,846.9	1,721.4
TOTAL ASSETS	$ 16,289.4	$ 15,711.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2024 and December 31, 2023
(Unaudited)

	September 30, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 0.9	$ 339.6
Accounts Payable:		
General	363.3	280.4
Affiliated Companies	124.8	121.3
Long-term Debt Due Within One Year – Nonaffiliated	748.6	538.8
Risk Management Liabilities	7.6	15.9
Customer Deposits	85.5	80.0
Accrued Taxes	129.5	117.6
Accrued Interest	95.6	58.9
Obligations Under Operating Leases	13.9	14.6
Other Current Liabilities	165.3	118.8
TOTAL CURRENT LIABILITIES	1,735.0	1,685.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,910.6	5,049.5
Deferred Income Taxes	2,020.8	2,011.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,100.4	1,081.9
Asset Retirement Obligations	774.3	442.5
Employee Benefits and Pension Obligations	31.6	32.8
Obligations Under Operating Leases	56.9	59.8
Deferred Credits and Other Noncurrent Liabilities	49.9	70.9
TOTAL NONCURRENT LIABILITIES	8,944.5	8,749.3
TOTAL LIABILITIES	10,679.5	10,435.2
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	1,939.5	1,834.5
Retained Earnings	3,415.1	3,185.5
Accumulated Other Comprehensive Income (Loss)	(5.1)	(3.7)
TOTAL COMMON SHAREHOLDER'S EQUITY	5,609.9	5,276.7
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 16,289.4	$ 15,711.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2024	2023
OPERATING ACTIVITIES		
Net Income	$ 304.6	$ 247.3
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	444.5	424.8
Deferred Income Taxes	(23.0)	5.2
Allowance for Equity Funds Used During Construction	(11.4)	(8.7)
Mark-to-Market of Risk Management Contracts	(33.6)	21.7
Deferred Fuel Over/Under-Recovery, Net	124.1	108.2
Change in Other Noncurrent Assets	(13.1)	24.4
Change in Other Noncurrent Liabilities	5.6	(29.9)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	3.6	80.2
Fuel, Materials and Supplies	62.2	(114.0)
Accounts Payable	50.4	(129.5)
Accrued Taxes, Net	12.8	(12.4)
Other Current Assets	(24.7)	(6.5)
Other Current Liabilities	34.8	(0.6)
Net Cash Flows from Operating Activities	936.8	610.2
INVESTING ACTIVITIES		
Construction Expenditures	(708.7)	(813.4)
Change in Advances to Affiliates, Net	—	0.5
Other Investing Activities	14.4	(2.9)
Net Cash Flows Used for Investing Activities	(694.3)	(815.8)
FINANCING ACTIVITIES		
Capital Contribution from Parent	109.5	6.5
Return of Capital to Parent	(4.5)	—
Issuance of Long-term Debt – Nonaffiliated	480.8	200.0
Change in Advances from Affiliates, Net	(338.7)	20.3
Retirement of Long-term Debt – Nonaffiliated	(413.5)	(26.5)
Principal Payments for Finance Lease Obligations	(6.5)	(6.2)
Dividends Paid on Common Stock	(75.0)	—
Other Financing Activities	0.3	1.0
Net Cash Flows from (Used for) Financing Activities	(247.6)	195.1
Net Decrease in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(5.1)	(10.5)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	19.9	21.9
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 14.8	$ 11.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 159.6	$ 166.6
Net Cash Paid for Income Taxes	27.4	40.3
Cash Paid (Received) for Transferable Tax Credits	(0.2)	—
Noncash Acquisitions Under Finance Leases	0.9	4.1
Construction Expenditures Included in Current Liabilities as of September 30,	129.9	138.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in millions of KWhs)			
Retail:				
Residential	1,552	1,421	4,152	3,998
Commercial	1,450	1,360	4,015	3,756
Industrial	1,901	1,876	5,562	5,501
Miscellaneous	10	12	35	39
Total Retail	4,913	4,669	13,764	13,294
Wholesale (a)	1,305	1,246	4,042	4,210
Total KWhs	6,218	5,915	17,806	17,504

(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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in degree days)			
Actual – Heating (a)	—	—	1,826	1,914
Normal – Heating (b)	6	7	2,428	2,430
Actual – Cooling (c)	608	516	965	722
Normal – Cooling (b)	583	588	852	857

(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 2023 to 2024 Net Income
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Net Income	$ 93.0	$ 270.6
Changes in Revenues:		
Retail Revenues	31.9	21.1
Off-system Sales	25.0	25.8
Transmission Revenues	2.5	10.0
Other Revenues	(2.2)	(0.2)
Total Change in Revenues	57.2	56.7
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	11.1	(4.5)
Purchased Electricity from AEP Affiliates	(6.0)	(29.8)
Other Operation and Maintenance	(11.9)	(40.5)
Asset Impairments and Other Related Charges	—	(13.4)
Depreciation and Amortization	(15.9)	(6.3)
Taxes Other Than Income Taxes	1.3	(6.5)
Other Income	(1.2)	1.6
Non-Service Cost Components of Net Periodic Benefit Cost	(0.9)	(3.4)
Interest Expense	(2.7)	3.1
Total Change in Expenses and Other	(26.2)	(99.7)
Income Tax Expense	55.1	131.7
2024 Net Income	$ 179.1	$ 359.3

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Retail Revenues** increased $32 million primarily due to the following:
  - A $31 million increase in weather-normalized margins in all customer classes.
  - A $15 million increase in rider revenues.
  - A $9 million increase in weather-related usage primarily due to an 18% increase in cooling degree days.
  - A $7 million increase due to the implementation of new base rates in Indiana and Michigan.

  These increases were partially offset by:
  - A $12 million decrease due to regulatory provisions for refund.
  - A $12 million decrease in fuel revenues primarily driven by lower fuel rates in Indiana.
- **Off-system Sales** increased $25 million primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $11 million primarily due to decreased recoverable fuel costs and a decrease due to a regulatory true-up associated with a final commission order, partially offset by an increase in merchant generation at Rockport Plant and an increase in recoverable purchased power costs.
- **Purchased Electricity from AEP Affiliates** increased $6 million primarily due to an increase in purchased electricity from Rockport Plant.

- **Other Operation and Maintenance** expenses increased $12 million primarily due to an increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
- **Depreciation and Amortization** expenses increased $16 million primarily due to an increase in regulatory reserves related to Nuclear PTCs.
- **Income Tax Expense** decreased $55 million primarily due to a $61 million decrease related to estimated Nuclear PTCs.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Retail Revenues** increased $21 million primarily due to the following:
  - A $22 million increase in weather-related usage primarily due to a 34% increase in cooling degree days.
  - An $18 million increase in weather-normalized margins in the residential and commercial classes.
  - A $12 million increase due to the implementation of new base rates in Indiana and Michigan.
  - A $9 million increase in rider revenues.

  These increases were partially offset by:
  - A $34 million decrease due to regulatory provisions for refund.
  - A $10 million decrease in fuel revenues primarily driven by lower fuel rates in Indiana.
- **Off-system Sales** increased $26 million primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales.
- **Transmission Revenues** increased $10 million primarily due to continued investment in transmission assets.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $5 million primarily due to an increase in merchant generation at Rockport Plant, partially offset by decreased recoverable fuel costs.
- **Purchased Electricity from AEP Affiliates** increased $30 million primarily due to an increase in purchased electricity from Rockport Plant.
- **Other Operation and Maintenance** expenses increased $41 million primarily due to the following:
  - A $23 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $15 million increase in employee-related expenses due to the voluntary severance program.
  - An $8 million increase in non-utility operation expenses due to an increase in RTD expenses and merchant operation expenses at Rockport Plant.

  These increases were partially offset by:
  - A $4 million decrease in distribution expenses primarily due to a decrease in vegetation management costs.
  - A $4 million decrease in nuclear expenses at Cook Plant primarily due to lower refueling outage expenses.
  - A $3 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2024.
- **Asset Impairments and Other Related Charges** increased $13 million due to the Federal EPA's revised CCR rules.
- **Depreciation and Amortization** expenses increased $6 million primarily due to the following:
  - A $13 million increase in regulatory reserves related to Nuclear PTCs.
  - A $9 million increase due to a higher depreciable base.

  These increases were partially offset by:
  - An $18 million decrease primarily due to the deferral of Excess ADIT as a result of the PLR received regarding the treatment of stand-alone NOLCs and the timing of refunds to customers under rate rider mechanisms.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to an increase in property taxes resulting from additional capital expenditures.
- **Income Tax Expense** decreased $132 million primarily due to the following:
  - A $67 million decrease due to a reduction in Excess ADIT as a result of the IRS PLR and I&M Michigan jurisdictional treatment of stand-alone NOLCs.
  - A $61 million decrease due to estimated Nuclear PTCs.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
REVENUES				
Electric Generation, Transmission and Distribution	$ 714.9	$ 656.1	$ 1,932.3	$ 1,879.3
Sales to AEP Affiliates	1.3	0.6	5.2	3.7
Other Revenues – Affiliated	15.2	15.4	50.7	45.8
Other Revenues – Nonaffiliated	2.1	4.2	7.0	9.7
TOTAL REVENUES	733.5	676.3	1,995.2	1,938.5
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	118.2	129.3	326.9	322.4
Purchased Electricity from AEP Affiliates	63.0	57.0	169.0	139.2
Other Operation	180.0	168.9	548.5	508.7
Maintenance	58.1	57.3	173.7	173.0
Asset Impairments and Other Related Charges	—	—	13.4	—
Depreciation and Amortization	132.6	116.7	359.2	352.9
Taxes Other Than Income Taxes	21.0	22.3	68.9	62.4
TOTAL EXPENSES	572.9	551.5	1,659.6	1,558.6
OPERATING INCOME	160.6	124.8	335.6	379.9
Other Income (Expense):				
Other Income	3.3	4.5	9.7	8.1
Non-Service Cost Components of Net Periodic Benefit Cost	6.8	7.7	20.0	23.4
Interest Expense	(35.7)	(33.0)	(98.9)	(102.0)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	135.0	104.0	266.4	309.4
Income Tax Expense (Benefit)	(44.1)	11.0	(92.9)	38.8
NET INCOME	$ 179.1	$ 93.0	$ 359.3	$ 270.6

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	**2023**	**2024**	**2023**
Net Income	$ 179.1	$ 93.0	$ 359.3	$ 270.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0.1 for the Three Months Ended September 30, 2024 and 2023, Respectively, and $0.1 and $(0.1) for the Nine Months Ended September 30, 2024 and 2023, Respectively	0.1	0.1	0.3	(0.5)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended September 30, 2024 and 2023, Respectively, and $0 and $(0.6) for the Nine Months Ended September 30, 2024 and 2023, Respectively	—	(0.2)	(0.1)	(2.4)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	0.1	(0.1)	0.2	(2.9)
TOTAL COMPREHENSIVE INCOME	$ 179.2	$ 92.9	$ 359.5	$ 267.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
Capital Contribution from Parent		1.6			1.6
Common Stock Dividends			(75.0)		(75.0)
Net Income			93.0		93.0
Other Comprehensive Loss				(0.1)	(0.1)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2023	$ 56.6	$ 990.5	$ 2,096.3	$ (3.2)	$ 3,140.2
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2023	$ 56.6	$ 997.6	$ 2,086.6	$ (0.6)	$ 3,140.2
Common Stock Dividends			(37.5)		(37.5)
Net Income			145.0		145.0
Other Comprehensive Income				0.1	0.1
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2024	56.6	997.6	2,194.1	(0.5)	3,247.8
Capital Contribution from Parent		5.0			5.0
Common Stock Dividends			(37.5)		(37.5)
Net Income			35.2		35.2
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2024	56.6	1,002.6	2,191.8	(0.5)	3,250.5
Return of Capital to Parent		(1.8)			(1.8)
Common Stock Dividends			(37.5)		(37.5)
Net Income			179.1		179.1
Other Comprehensive Income				0.1	0.1
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2024	$ 56.6	$ 1,000.8	$ 2,333.4	$ (0.4)	$ 3,390.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2024 and December 31, 2023
(in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4.1	$ 2.1
Accounts Receivable:		
Customers	43.5	66.9
Affiliated Companies	72.6	65.0
Accrued Unbilled Revenues	29.1	0.2
Miscellaneous	4.7	8.2
Total Accounts Receivable	149.9	140.3
Fuel	71.9	88.1
Materials and Supplies	210.6	208.2
Risk Management Assets	21.7	27.8
Accrued Tax Benefits	48.2	—
Regulatory Asset for Under-Recovered Fuel Costs	12.0	14.8
Prepayments and Other Current Assets	55.2	46.7
TOTAL CURRENT ASSETS	573.6	528.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,675.8	5,646.8
Transmission	1,951.3	1,906.4
Distribution	3,467.2	3,254.0
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	919.4	898.5
Construction Work in Progress	360.2	301.7
Total Property, Plant and Equipment	12,373.9	12,007.4
Accumulated Depreciation, Depletion and Amortization	4,600.9	4,378.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,773.0	7,629.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	572.6	406.3
Spent Nuclear Fuel and Decommissioning Trusts	4,425.8	3,860.2
Operating Lease Assets	50.2	53.8
Deferred Charges and Other Noncurrent Assets	272.7	330.7
TOTAL OTHER NONCURRENT ASSETS	5,321.3	4,651.0
TOTAL ASSETS	$ 13,667.9	$ 12,808.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2024 and December 31, 2023
(dollars in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT LIABILITIES		
Advances from Affiliates	$ 77.0	$ 63.3
Accounts Payable:		
General	178.9	225.8
Affiliated Companies	88.0	107.3
Long-term Debt Due Within One Year – Nonaffiliated (September 30, 2024 and December 31, 2023 Amounts Include $93.2 and $81.4, Respectively, Related to DCC Fuel)	284.1	83.7
Customer Deposits	53.5	72.2
Accrued Taxes	96.8	104.7
Accrued Interest	38.0	41.3
Obligations Under Operating Leases	13.1	16.8
Regulatory Liability for Over-Recovered Fuel Costs	6.7	23.2
Other Current Liabilities	114.2	91.9
TOTAL CURRENT LIABILITIES	950.3	830.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,233.4	3,415.7
Deferred Income Taxes	1,213.5	1,169.9
Regulatory Liabilities and Deferred Investment Tax Credits	2,544.4	2,052.3
Asset Retirement Obligations	2,243.2	2,104.3
Obligations Under Operating Leases	37.9	37.7
Deferred Credits and Other Noncurrent Liabilities	54.8	57.7
TOTAL NONCURRENT LIABILITIES	9,327.2	8,837.6
TOTAL LIABILITIES	10,277.5	9,667.8
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	1,000.8	997.6
Retained Earnings	2,333.4	2,086.6
Accumulated Other Comprehensive Income (Loss)	(0.4)	(0.6)
TOTAL COMMON SHAREHOLDER'S EQUITY	3,390.4	3,140.2
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 13,667.9	$ 12,808.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2024	**2023**
OPERATING ACTIVITIES		
Net Income	$ 359.3	$ 270.6
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	359.2	352.9
Deferred Income Taxes	(70.7)	(16.4)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	(3.2)	44.3
Asset Impairments and Other Related Charges	13.4	—
Allowance for Equity Funds Used During Construction	(10.1)	(6.6)
Mark-to-Market of Risk Management Contracts	16.3	(4.7)
Amortization of Nuclear Fuel	74.3	75.7
Deferred Fuel Over/Under-Recovery, Net	(13.7)	52.9
Change in Other Noncurrent Assets	24.4	3.1
Change in Other Noncurrent Liabilities	49.5	9.0
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(8.1)	82.5
Fuel, Materials and Supplies	13.8	(42.7)
Accounts Payable	(57.7)	(34.8)
Accrued Taxes, Net	(56.1)	(25.3)
Other Current Assets	(2.0)	(3.4)
Other Current Liabilities	(10.2)	(22.7)
Net Cash Flows from Operating Activities	678.4	734.4
INVESTING ACTIVITIES		
Construction Expenditures	(434.7)	(418.4)
Change in Advances to Affiliates, Net	—	1.8
Purchases of Investment Securities	(2,389.0)	(2,182.8)
Sales of Investment Securities	2,336.0	2,139.3
Acquisitions of Nuclear Fuel	(98.4)	(60.9)
Other Investing Activities	5.7	4.9
Net Cash Flows Used for Investing Activities	(580.4)	(516.1)
FINANCING ACTIVITIES		
Capital Contribution from Parent	5.0	1.7
Return of Capital to Parent	(1.8)	—
Issuance of Long-term Debt – Nonaffiliated	80.4	494.8
Change in Advances from Affiliates, Net	13.7	(249.9)
Retirement of Long-term Debt – Nonaffiliated	(76.1)	(324.1)
Principal Payments for Finance Lease Obligations	(5.2)	(5.4)
Dividends Paid on Common Stock	(112.5)	(137.5)
Other Financing Activities	0.5	0.6
Net Cash Flows Used for Financing Activities	(96.0)	(219.8)
Net Increase (Decrease) in Cash and Cash Equivalents	2.0	(1.5)
Cash and Cash Equivalents at Beginning of Period	2.1	4.2
Cash and Cash Equivalents at End of Period	$ 4.1	$ 2.7
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 111.5	$ 100.1
Net Cash Paid (Received) for Income Taxes	(4.4)	36.2
Noncash Acquisitions Under Finance Leases	1.1	3.6
Construction Expenditures Included in Current Liabilities as of September 30,	69.6	70.6
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	8.2	9.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

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 September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in millions of KWhs)			
Retail:				
Residential	4,090	3,761	10,905	10,323
Commercial	5,388	4,553	15,138	12,503
Industrial	3,544	3,536	10,585	10,456
Miscellaneous	24	24	77	78
Total Retail (a)	13,046	11,874	36,705	33,360
Wholesale (b)	504	485	1,347	1,366
Total KWhs	13,550	12,359	38,052	34,726

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

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

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in degree days)			
Actual – Heating (a)	—	—	1,573	1,521
Normal – Heating (b)	4	4	2,056	2,080
Actual – Cooling (c)	844	625	1,266	809
Normal – Cooling (b)	699	697	1,008	1,005

(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 2023 to 2024 Net Income
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Net Income	$ 80.5	$ 226.2
Changes in Revenues:		
Retail Revenues	3.8	6.0
Off-system Sales	(2.1)	(11.7)
Transmission Revenues	0.5	0.5
Other Revenues	12.5	26.3
Total Change in Revenues	14.7	21.1
Changes in Expenses and Other:		
Purchased Electricity for Resale	61.6	278.1
Purchased Electricity from AEP Affiliates	23.9	(36.6)
Other Operation and Maintenance	(50.4)	(121.1)
Asset Impairments and Other Related Charges	—	(52.9)
Depreciation and Amortization	(4.8)	(69.2)
Taxes Other Than Income Taxes	(4.4)	(43.0)
Other Income	0.8	0.6
Allowance for Equity Funds Used During Construction	0.8	4.9
Non-Service Cost Components of Net Periodic Benefit Cost	(1.1)	(3.3)
Interest Expense	(4.8)	(13.0)
Total Change in Expenses and Other	21.6	(55.5)
Income Tax Expense	(4.1)	9.9
2024 Net Income	$ 112.7	$ 201.7

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Retail Revenues** increased $4 million primarily due to the following:
  - A $105 million increase in revenue from rate riders.
  - A $14 million increase in weather-related usage driven by a 35% increase in cooling degree days.

  These increases were partially offset by:
  - A $104 million decrease due to lower customer participation in OPCo’s SSO, partially offset by higher prices.
  - A $12 million decrease in weather-normalized revenues in the industrial class.
- **Other Revenues** increased $13 million primarily due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.

Expenses and Other changed between years as follows:

- **Purchased Electricity for Resale** expenses decreased $62 million primarily due to the following:
  - An $80 million decrease in recoverable auction purchases primarily due to lower volumes driven by lower customer participation in OPCo’s SSO.

  This decrease was partially offset by:
  - A $19 million increase in recoverable OVEC costs.

- **Purchased Electricity from AEP Affiliates** expenses decreased $24 million primarily due to decreased recoverable auction purchases in OPCo's SSO.
- **Other Operation and Maintenance** expenses increased $50 million primarily due to the following:
  - A $31 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - An $11 million increase related to recoverable energy assistance program expenses for qualified Ohio customers.
  - An $8 million increase in distribution expenses primarily related to recoverable storm restoration costs and recoverable vegetation management expenses.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Retail Revenues** increased $6 million primarily due to the following:
  - A $279 million increase in revenue from rate riders.
  - A $44 million increase in weather-related usage driven by a 56% increase in cooling degree days.

  These increases were partially offset by:
  - A $306 million decrease due to lower customer participation in OPCo's SSO, partially offset by higher prices.
  - A $15 million decrease in weather-normalized revenues in the industrial class, partially offset by residential and commercial classes.
- **Off-system Sales** decreased $12 million primarily due to 2023 PJM settlements related to winter storm Elliott.
- **Other Revenues** increased $26 million due to the following:
  - A $33 million increase due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.

  This increase was partially offset by:
  - A $9 million decrease in recoverable sales of renewable energy credits.

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

- **Purchased Electricity for Resale** expenses decreased $278 million primarily due to the following:
  - A $342 million decrease in recoverable auction purchases primarily due to lower volumes driven by lower customer participation in OPCo's SSO, partially offset by higher prices.
  - A $16 million decrease in recoverable alternative energy rider expenses.

  These decreases were partially offset by:
  - An $81 million increase in recoverable OVEC costs.
- **Purchased Electricity from AEP Affiliates** expenses increased $37 million primarily due to increased recoverable purchases in OPCo's SSO auction.
- **Other Operation and Maintenance** expenses increased $121 million primarily due to the following:
  - A $73 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $19 million increase in distribution expenses primarily due to recoverable storm restoration costs and recoverable vegetation management expenses.
  - A $16 million increase related to recoverable energy assistance program expenses for qualified Ohio customers.
  - A $15 million increase in employee-related expenses due to the voluntary severance program.
- **Asset Impairments and Other Related Charges** increased $53 million primarily due to Federal EPA revised CCR rules.
- **Depreciation and Amortization** expenses increased $69 million primarily due to a higher depreciable base and an increase in recoverable rider depreciable assets.
- **Taxes Other Than Income Taxes** increased $43 million primarily due to the following:
  - A $35 million increase due to higher property taxes driven by additional investments in transmission and distribution assets and tax rate changes.
  - An $8 million increase in state excise taxes due to increased billed KWh in 2024 resulting in a higher tax burden.
- **Interest Expense** increased $13 million primarily due to higher debt balances and interest rates.
- **Income Tax Expense** decreased $10 million primarily due to a decrease in pretax book income.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
REVENUES				
Electricity, Transmission and Distribution	$ 995.8	$ 978.7	$ 2,899.0	$ 2,869.3
Sales to AEP Affiliates	5.6	7.8	17.0	23.6
Other Revenues	2.8	3.0	8.3	10.3
TOTAL REVENUES	1,004.2	989.5	2,924.3	2,903.2
EXPENSES				
Purchased Electricity for Resale	199.1	260.7	642.8	920.9
Purchased Electricity from AEP Affiliates	14.1	38.0	86.2	49.6
Other Operation	343.2	296.9	920.2	836.1
Maintenance	66.3	62.2	194.7	157.7
Asset Impairments and Other Related Charges	—	—	52.9	—
Depreciation and Amortization	86.1	81.3	293.9	224.7
Taxes Other Than Income Taxes	136.9	132.5	425.0	382.0
TOTAL EXPENSES	845.7	871.6	2,615.7	2,571.0
OPERATING INCOME	158.5	117.9	308.6	332.2
Other Income (Expense):				
Other Income	0.9	0.1	1.0	0.4
Allowance for Equity Funds Used During Construction	6.4	5.6	16.2	11.3
Non-Service Cost Components of Net Periodic Benefit Cost	5.4	6.5	16.2	19.5
Interest Expense	(38.7)	(33.9)	(109.9)	(96.9)
INCOME BEFORE INCOME TAX EXPENSE	132.5	96.2	232.1	266.5
Income Tax Expense	19.8	15.7	30.4	40.3
NET INCOME	$ 112.7	$ 80.5	$ 201.7	$ 226.2

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Total
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
Net Income			80.5	80.5
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2023	$ 321.2	$ 1,012.8	$ 2,155.3	$ 3,489.3
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	$ 321.2	$ 1,012.8	$ 2,237.3	$ 3,571.3
Net Income			70.6	70.6
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2024	321.2	1,012.8	2,307.9	3,641.9
Net Income			18.4	18.4
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2024	321.2	1,012.8	2,326.3	3,660.3
Capital Contribution from Parent		0.8		0.8
Net Income			112.7	112.7
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2024	$ 321.2	$ 1,013.6	$ 2,439.0	$ 3,773.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2024 and December 31, 2023
(in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 9.6	$ 6.4
Advances to Affiliates	97.4	—
Accounts Receivable:		
Customers	83.0	39.2
Affiliated Companies	122.6	129.2
Miscellaneous	8.7	2.3
Total Accounts Receivable	214.3	170.7
Materials and Supplies	150.1	183.9
Prepayments and Other Current Assets	26.2	16.8
TOTAL CURRENT ASSETS	497.6	377.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	3,529.9	3,395.1
Distribution	7,143.3	6,839.4
Other Property, Plant and Equipment	1,192.6	1,125.0
Construction Work in Progress	768.7	654.0
Total Property, Plant and Equipment	12,634.5	12,013.5
Accumulated Depreciation and Amortization	2,855.5	2,713.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,779.0	9,299.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	394.9	455.0
Operating Lease Assets	62.5	69.9
Deferred Charges and Other Noncurrent Assets	336.1	641.1
TOTAL OTHER NONCURRENT ASSETS	793.5	1,166.0
TOTAL ASSETS	$ 11,070.1	$ 10,843.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2024 and December 31, 2023
(Unaudited)

	September 30, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 110.5
Accounts Payable:		
General	312.0	320.7
Affiliated Companies	155.8	154.2
Risk Management Liabilities	6.3	6.8
Customer Deposits	68.1	62.0
Accrued Taxes	439.9	763.3
Accrued Interest	61.0	38.5
Obligations Under Operating Leases	12.6	13.5
Other Current Liabilities	145.8	144.8
TOTAL CURRENT LIABILITIES	1,201.5	1,614.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,715.0	3,366.8
Long-term Risk Management Liabilities	45.3	43.9
Deferred Income Taxes	1,179.5	1,152.7
Regulatory Liabilities and Deferred Investment Tax Credits	997.0	1,003.6
Obligations Under Operating Leases	50.3	56.7
Deferred Credits and Other Noncurrent Liabilities	107.7	34.4
TOTAL NONCURRENT LIABILITIES	6,094.8	5,658.1
TOTAL LIABILITIES	7,296.3	7,272.4
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	1,013.6	1,012.8
Retained Earnings	2,439.0	2,237.3
TOTAL COMMON SHAREHOLDER'S EQUITY	3,773.8	3,571.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 11,070.1	$ 10,843.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Nine Months Ended September 30,	
	2024	**2023**
OPERATING ACTIVITIES		
Net Income	$ 201.7	$ 226.2
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	293.9	224.7
Deferred Income Taxes	0.2	29.4
Asset Impairments and Other Related Charges	52.9	—
Allowance for Equity Funds Used During Construction	(16.2)	(11.3)
Mark-to-Market of Risk Management Contracts	0.9	11.6
Property Taxes	286.6	282.4
Change in Other Noncurrent Assets	19.2	(95.5)
Change in Other Noncurrent Liabilities	47.2	(47.7)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(39.8)	4.3
Materials and Supplies	33.8	5.3
Accounts Payable	(43.4)	1.8
Customer Deposits	6.1	(37.3)
Accrued Taxes, Net	(322.3)	(367.3)
Other Current Assets	(11.9)	(2.3)
Other Current Liabilities	17.2	0.4
Net Cash Flows from Operating Activities	526.1	224.7
INVESTING ACTIVITIES		
Construction Expenditures	(688.5)	(769.0)
Change in Advances to Affiliates, Net	(97.4)	—
Other Investing Activities	29.4	33.9
Net Cash Flows Used for Investing Activities	(756.5)	(735.1)
FINANCING ACTIVITIES		
Capital Contribution from Parent	0.8	175.0
Issuance of Long-term Debt – Nonaffiliated	346.3	395.0
Change in Advances from Affiliates, Net	(110.5)	(59.6)
Retirement of Long-term Debt – Nonaffiliated	—	(0.6)
Principal Payments for Finance Lease Obligations	(4.0)	(3.7)
Other Financing Activities	1.0	1.5
Net Cash Flows from Financing Activities	233.6	507.6
Net Increase (Decrease) in Cash and Cash Equivalents	3.2	(2.8)
Cash and Cash Equivalents at Beginning of Period	6.4	9.6
Cash and Cash Equivalents at End of Period	$ 9.6	$ 6.8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 82.8	$ 76.5
Net Cash Paid (Received) for Income Taxes	(5.1)	16.0
Noncash Acquisitions Under Finance Leases	1.1	3.3
Construction Expenditures Included in Current Liabilities as of September 30,	126.8	99.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

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 September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in millions of KWhs)			
Retail:				
Residential	2,170	2,197	5,084	4,943
Commercial	1,733	1,539	4,348	3,934
Industrial	1,524	1,557	4,436	4,503
Miscellaneous	371	373	981	965
Total Retail	5,798	5,666	14,849	14,345
Wholesale (a)	24	59	135	132
Total KWhs	5,822	5,725	14,984	14,477

(a) Includes 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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in degree days)			
Actual – Heating (a)	—	—	917	899
Normal – Heating (b)	—	—	1,088	1,100
Actual – Cooling (c)	1,433	1,554	2,263	2,202
Normal – Cooling (b)	1,429	1,425	2,111	2,102

(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 2023 to 2024 Net Income
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Net Income	$ 139.4	$ 188.1
Changes in Revenues:		
Retail Revenues (a)	(30.4)	(88.2)
Transmission Revenues	(0.2)	(0.1)
Other Revenues	1.8	14.4
Total Change in Revenues	(28.8)	(73.9)
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	33.3	127.6
Other Operation and Maintenance	(11.6)	(43.6)
Depreciation and Amortization	(8.8)	(14.3)
Taxes Other Than Income Taxes	(1.6)	(10.7)
Interest Income	(0.1)	(0.7)
Allowance for Equity Funds Used During Construction	(1.1)	(0.7)
Non-Service Cost Components of Net Periodic Benefit Cost	(0.7)	(2.2)
Interest Expense	(1.0)	7.3
Total Change in Expenses and Other	8.4	62.7
Income Tax Benefit	(5.3)	45.1
2024 Net Income	$ 113.7	$ 222.0

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

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Retail Revenues** decreased $30 million primarily due to the following:
  - A $39 million decrease in fuel revenue primarily due to lower authorized fuel rates.
  - A $9 million decrease in weather-related usage primarily due to an 8% decrease in cooling degree days.

  These decreases were partially offset by:
  - An $11 million increase in weather-normalized margins primarily in the residential class.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $33 million primarily due to the lower current year amortization of under-recovered fuel regulatory assets driven by lower authorized fuel rates.
- **Other Operation and Maintenance** expenses increased $12 million primarily due to the following:
  - A $7 million increase in transmission expenses primarily due to an increase in SPP expenses.
  - A $3 million increase in overhead line maintenance expenses.
- **Depreciation and Amortization** expenses increased $9 million primarily due to a higher depreciable base, implementation of new rates and the amortization of regulatory assets related to NCWF.
- **Income Tax Benefit** decreased $5 million primarily due to the following:
  - A $13 million decrease due to a decrease in amortization of Excess ADIT.

  This decrease was partially offset by:
  - A $4 million increase due to a decrease in pretax book income.
  - A $3 million increase due to a decrease in state income tax.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Retail Revenues** decreased $88 million primarily due to the following:
    - A $137 million decrease in fuel revenue primarily due to lower authorized fuel rates.

  This decrease was partially offset by:
    - A $32 million increase in base rate and rider revenues.
- **Other Revenues** increased $14 million primarily due to associated business development revenues driven by costs associated with a third-party construction project.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $128 million primarily due to the lower current year amortization of under-recovered fuel regulatory assets driven by lower authorized fuel rates.
- **Other Operation and Maintenance** expenses increased $44 million primarily due to the following:
    - A $16 million increase in transmission expenses primarily due to an increase in SPP expenses.
    - A $13 million increase in associated business development expenses primarily due to partially reimbursable development costs associated with a third-party construction project.
    - A $10 million increase in employee-related expenses due to the voluntary severance program.
- **Depreciation and Amortization** expenses increased $14 million primarily due to a higher depreciable base, implementation of new rates and the amortization of regulatory assets related to NCWF.
- **Taxes Other Than Income Taxes** increased $11 million primarily due to an increase in property taxes.
- **Interest Expense** decreased $7 million primarily due to the recognition of debt carrying charges as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail rate making.
- **Income Tax Benefit** increased $45 million primarily due to a reduction in Excess ADIT regulatory liabilities as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail rate making.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	**2023**	**2024**	**2023**
REVENUES				
Electric Generation, Transmission and Distribution	$ 612.9	$ 642.6	$ 1,439.1	$ 1,529.8
Sales to AEP Affiliates	1.1	0.2	5.7	1.0
Other Revenues	1.4	1.4	17.2	5.1
TOTAL REVENUES	615.4	644.2	1,462.0	1,535.9
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	284.8	318.1	613.7	741.3
Other Operation	112.2	103.9	328.1	283.5
Maintenance	28.7	25.4	81.7	82.7
Depreciation and Amortization	70.6	61.8	202.1	187.8
Taxes Other Than Income Taxes	18.8	17.2	60.2	49.5
TOTAL EXPENSES	515.1	526.4	1,285.8	1,344.8
OPERATING INCOME	100.3	117.8	176.2	191.1
Other Income (Expense):				
Interest Income	0.2	0.3	0.7	1.4
Allowance for Equity Funds Used During Construction	1.3	2.4	4.6	5.3
Non-Service Cost Components of Net Periodic Benefit Cost	2.9	3.6	8.5	10.7
Interest Expense	(26.5)	(25.5)	(70.2)	(77.5)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	78.2	98.6	119.8	131.0
Income Tax Expense (Benefit)	(35.5)	(40.8)	(102.2)	(57.1)
NET INCOME	$ 113.7	$ 139.4	$ 222.0	$ 188.1

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
Net Income	$ 113.7	$ 139.4	$ 222.0	$ 188.1
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(2.3) and $0 for the Three Months Ended September 30, 2024 and 2023, Respectively, and $(2.3) and $(0.4) for the Nine Months Ended September 30, 2024 and 2023, Respectively	(8.6)	—	(8.6)	(1.5)
TOTAL COMPREHENSIVE INCOME	$ 105.1	$ 139.4	$ 213.4	$ 186.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 157.2	$ 1,042.6	$ 1,218.0	$ 1.3	$ 2,419.1
Common Stock Dividends			(17.5)		(17.5)
Net Loss			(2.3)		(2.3)
Other 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
Return of Capital to Parent		(2.5)			(2.5)
Net 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
Capital Contribution from Parent		0.6			0.6
Common Stock Dividends			(17.5)		(17.5)
Net Income			139.4		139.4
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2023	$ 157.2	$ 1,040.7	$ 1,371.1	$ (0.2)	$ 2,568.8
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	$ 157.2	$ 1,039.3	$ 1,374.3	$ (0.2)	$ 2,570.6
Common Stock Dividends			(35.0)		(35.0)
Net Income			72.0		72.0
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2024	157.2	1,039.3	1,411.3	(0.2)	2,607.6
Capital Contribution from Parent		0.2			0.2
Common Stock Dividends			(35.0)		(35.0)
Net Income			36.3		36.3
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2024	157.2	1,039.5	1,412.6	(0.2)	2,609.1
Common Stock Dividends			(35.0)		(35.0)
Net Income			113.7		113.7
Other Comprehensive Loss				(8.6)	(8.6)
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2024	$ 157.2	$ 1,039.5	$ 1,491.3	$ (8.8)	$ 2,679.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2024 and December 31, 2023
(in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4.8	$ 2.5
Accounts Receivable:		
Customers	59.5	107.6
Affiliated Companies	46.2	31.0
Miscellaneous	0.4	0.8
Total Accounts Receivable	106.1	139.4
Fuel	23.2	33.7
Materials and Supplies	105.2	106.9
Risk Management Assets	28.4	19.0
Accrued Tax Benefits	17.5	31.0
Regulatory Asset for Under-Recovered Fuel Costs	27.4	118.3
Prepayments and Other Current Assets	30.3	18.7
TOTAL CURRENT ASSETS	342.9	469.5
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	2,760.2	2,695.5
Transmission	1,272.2	1,228.3
Distribution	3,609.2	3,450.8
Other Property, Plant and Equipment	525.7	505.9
Construction Work in Progress	404.7	313.7
Total Property, Plant and Equipment	8,572.0	8,194.2
Accumulated Depreciation and Amortization	2,189.2	2,081.9
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,382.8	6,112.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	524.9	522.7
Employee Benefits and Pension Assets	71.9	68.4
Operating Lease Assets	107.6	112.8
Deferred Charges and Other Noncurrent Assets	61.5	49.2
TOTAL OTHER NONCURRENT ASSETS	765.9	753.1
TOTAL ASSETS	$ 7,491.6	$ 7,334.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2024 and December 31, 2023
(Unaudited)

	September 30, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 98.5	$ 54.4
Accounts Payable:		
General	181.1	159.3
Affiliated Companies	57.7	56.7
Long-term Debt Due Within One Year – Nonaffiliated	250.6	0.6
Risk Management Liabilities	22.3	28.9
Customer Deposits	63.9	81.4
Accrued Taxes	71.2	30.7
Accrued Interest	22.7	30.7
Obligations Under Operating Leases	10.8	10.1
Other Current Liabilities	61.2	106.2
TOTAL CURRENT LIABILITIES	840.0	559.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,134.8	2,384.0
Deferred Income Taxes	888.6	831.2
Regulatory Liabilities and Deferred Investment Tax Credits	699.1	765.6
Asset Retirement Obligations	120.0	83.9
Obligations Under Operating Leases	102.1	106.8
Deferred Credits and Other Noncurrent Liabilities	27.8	33.8
TOTAL NONCURRENT LIABILITIES	3,972.4	4,205.3
TOTAL LIABILITIES	4,812.4	4,764.3
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	1,039.5	1,039.3
Retained Earnings	1,491.3	1,374.3
Accumulated Other Comprehensive Income (Loss)	(8.8)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,679.2	2,570.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,491.6	$ 7,334.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
OPERATING ACTIVITIES		
Net Income	$ 222.0	$ 188.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	202.1	187.8
Deferred Income Taxes	(12.7)	(13.6)
Allowance for Equity Funds Used During Construction	(4.6)	(5.3)
Mark-to-Market of Risk Management Contracts	(27.9)	(0.2)
Property Taxes	(14.8)	(14.0)
Deferred Fuel Over/Under-Recovery, Net	90.9	263.3
Change in Other Regulatory Assets	5.0	(66.1)
Change in Other Noncurrent Assets	(24.4)	(27.8)
Change in Other Noncurrent Liabilities	0.8	11.0
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	33.3	11.9
Fuel, Materials and Supplies	12.2	(11.6)
Accounts Payable	9.6	(19.5)
Accrued Taxes, Net	54.0	(9.5)
Other Current Assets	(15.3)	(3.0)
Other Current Liabilities	(67.0)	(10.8)
Net Cash Flows from Operating Activities	463.2	480.7
INVESTING ACTIVITIES		
Construction Expenditures	(402.9)	(401.1)
Change in Advances to Affiliates, Net	—	(9.2)
Acquisitions of Renewable Energy Facilities	—	(145.7)
Other Investing Activities	5.1	8.8
Net Cash Flows Used for Investing Activities	(397.8)	(547.2)
FINANCING ACTIVITIES		
Capital Contribution from Parent	0.2	0.6
Return of Capital to Parent	—	(2.5)
Issuance of Long-term Debt – Nonaffiliated	—	469.8
Change in Advances from Affiliates, Net	44.1	(364.2)
Retirement of Long-term Debt – Nonaffiliated	(0.4)	(0.4)
Principal Payments for Finance Lease Obligations	(2.5)	(2.5)
Dividends Paid on Common Stock	(105.0)	(35.0)
Other Financing Activities	0.5	0.4
Net Cash Flows from (Used for) Financing Activities	(63.1)	66.2
Net Increase (Decrease) in Cash and Cash Equivalents	2.3	(0.3)
Cash and Cash Equivalents at Beginning of Period	2.5	4.0
Cash and Cash Equivalents at End of Period	$ 4.8	$ 3.7
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 86.4	$ 67.4
Net Cash Paid (Received) for Income Taxes	(27.2)	(1.6)
Cash Paid (Received) for Transferable Tax Credits	(76.9)	—
Noncash Acquisitions Under Finance Leases	1.2	1.9
Construction Expenditures Included in Current Liabilities as of September 30,	76.7	91.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

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 September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in millions of KWhs)			
Retail:				
Residential	1,955	2,180	4,855	4,902
Commercial	1,617	1,689	4,287	4,269
Industrial	1,232	1,313	3,873	3,876
Miscellaneous	17	17	52	53
Total Retail	4,821	5,199	13,067	13,100
Wholesale (a)	1,567	1,668	4,281	4,226
Total KWhs	6,388	6,867	17,348	17,326

(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.

Summary of Heating and Cooling Degree Days

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(in degree days)			
Actual – Heating (a)	—	—	560	413
Normal – Heating (b)	1	—	722	730
Actual – Cooling (c)	1,591	1,715	2,721	2,673
Normal – Cooling (b)	1,439	1,435	2,237	2,223

(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.

Southwestern Electric Power Company
Reconciliation of 2023 to 2024
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

	Three Months Ended September 30,	Nine Months Ended September 30,
2023 Earnings Attributable to Common Shareholder	$ 157.5	$ 279.1
Changes in Revenues:		
Retail Revenues (a)	(26.9)	(175.5)
Off-system Sales	0.5	2.4
Transmission Revenues	7.3	10.2
Other Revenues	3.1	5.2
Total Change in Revenues	(16.0)	(157.7)
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	11.3	32.5
Other Operation and Maintenance	4.9	(47.8)
Depreciation and Amortization	(17.1)	(30.8)
Taxes Other Than Income Taxes	2.1	10.6
Interest Income	(1.0)	(3.4)
Allowance for Equity Funds Used During Construction	(1.4)	2.4
Non-Service Cost Components of Net Periodic Benefit Cost	(0.8)	(2.6)
Interest Expense	10.2	32.1
Total Change in Expenses and Other	8.2	(7.0)
Income Tax Benefit	(11.2)	163.1
Equity Earnings of Unconsolidated Subsidiary	0.1	0.1
Net Income Attributable to Noncontrolling Interest	0.5	(0.5)
2024 Earnings Attributable to Common Shareholder	$ 139.1	$ 277.1

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

Third Quarter of 2024 Compared to Third Quarter of 2023

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

- **Retail Revenues** decreased $27 million primarily due to the following:
  - A $13 million decrease in fuel revenue.
  - A $12 million decrease in weather-normalized margins primarily in the residential and industrial classes.
  - A $10 million decrease in weather-related usage primarily due to a 7% decrease in cooling degree days.

  These decreases were partially offset by:
  - An $8 million increase primarily due to formula rate increases in Arkansas.
- **Transmission Revenues** increased $7 million primarily due to an increase in transmission investment.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $11 million primarily due to a current year decrease in amortization of under-recovered fuel regulatory assets.
- **Depreciation and Amortization** expenses increased $17 million primarily due to an increase in amortization of regulatory assets and a higher depreciable base.

- **Interest Expense** decreased $10 million primarily due to the following:
  - An $8 million decrease due to the prior year amortization of carrying charges on storm-related regulatory assets.
  - A $3 million decrease due to the recognition of debt carrying charges as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail rate making.
- **Income Tax Benefit** decreased $11 million primarily due to the following:
  - A $5 million decrease due to a decrease in PTCs.
  - A $4 million decrease due to a decrease in amortization of Excess ADIT.

Nine Months Ended September 30, 2024 Compared to Nine Months Ended September 30, 2023

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

- **Retail Revenues** decreased $176 million primarily due to the recognition of a $160 million probable revenue refund associated with the Turk Plant and SWEPCo’s 2012 Texas Base Rate Case.
- **Transmission Revenues** increased $10 million primarily due to a $15 million increase in continued investment in transmission assets and load, partially offset by a $4 million reversal of a prior period provision for refund in 2023.
- **Other Revenues** increased $5 million primarily due to associated business development revenues driven by costs associated with a third-party construction project.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $33 million primarily due to a current year decrease in amortization of under-recovered fuel regulatory assets.
- **Other Operation and Maintenance** expenses increased $48 million primarily due to the following:
  - A $17 million increase in employee-related expenses primarily due to the voluntary severance program.
  - A $14 million increase due to a disallowance recorded on the remaining net book value of the Dolet Hills Power Station as a result of an LPSC approved settlement agreement in April 2024.
  - An $11 million increase in SPP transmission expenses.
  - A $5 million increase due to the prior year capitalization of previously expensed renewable generation pre-construction charges.
- **Depreciation and Amortization** expenses increased $31 million primarily due to an increase in amortization of regulatory assets and a higher depreciable base, partially offset by the recognition of a regulatory asset related to NOLCs.
- **Taxes Other Than Income Taxes** decreased $11 million primarily due to a decrease in property taxes.
- **Interest Expense** decreased $32 million primarily due to the decrease in the recognition of debt carrying charges as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail rate making.
- **Income Tax Benefit** increased $163 million primarily due to the following:
  - A $109 million increase due to a reduction in Excess ADIT regulatory liabilities as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail rate making.
  - A $34 million increase due to a decrease in pretax book income.
  - A $32 million increase due to the reversal of a regulatory liability related to the merchant portion of Turk Plant Excess ADIT as a result of the APSC's March 2024 denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
REVENUES				
Electric Generation, Transmission and Distribution	$ 625.1	$ 640.0	$ 1,680.5	$ 1,665.2
Sales to AEP Affiliates	21.9	14.4	52.3	45.7
Provision for Refund	(8.9)	(0.1)	(189.0)	(4.2)
Other Revenues	0.7	0.5	7.0	1.8
TOTAL REVENUES	638.8	654.8	1,550.8	1,708.5
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	204.1	215.4	582.1	614.6
Other Operation	95.1	96.9	324.3	281.3
Maintenance	35.3	38.4	125.9	121.1
Depreciation and Amortization	117.7	100.6	297.6	266.8
Taxes Other Than Income Taxes	34.1	36.2	93.8	104.4
TOTAL EXPENSES	486.3	487.5	1,423.7	1,388.2
OPERATING INCOME	152.5	167.3	127.1	320.3
Other Income (Expense):				
Interest Income	3.1	4.1	11.4	14.8
Allowance for Equity Funds Used During Construction	2.9	4.3	9.7	7.3
Non-Service Cost Components of Net Periodic Benefit Cost	2.6	3.4	7.6	10.2
Interest Expense	(31.9)	(42.1)	(75.1)	(107.2)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	129.2	137.0	80.7	245.4
Income Tax Expense (Benefit)	(10.5)	(21.7)	(198.8)	(35.7)
Equity Earnings of Unconsolidated Subsidiary	0.4	0.3	1.1	1.0
NET INCOME	140.1	159.0	280.6	282.1
Net Income Attributable to Noncontrolling Interest	1.0	1.5	3.5	3.0
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 139.1	$ 157.5	$ 277.1	$ 279.1

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	**2023**	**2024**	**2023**
Net Income	$ 140.1	$ 159.0	$ 280.6	$ 282.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $0 for the Three Months Ended September 30, 2024 and 2023, Respectively, and $(0.1) and $0.1 for the Nine Months Ended September 30, 2024 and 2023, Respectively	(0.1)	—	(0.2)	0.3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $(0.1) for the Three Months Ended September 30, 2024 and 2023, Respectively, and $(0.1) and $(0.3) for the Nine Months Ended September 30, 2024 and 2023, Respectively	(0.1)	(0.4)	(0.2)	(1.0)
TOTAL OTHER COMPREHENSIVE LOSS	(0.2)	(0.4)	(0.4)	(0.7)
TOTAL COMPREHENSIVE INCOME	139.9	158.6	280.2	281.4
Total Comprehensive Income Attributable to Noncontrolling Interest	1.0	1.5	3.5	3.0
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 138.9	$ 157.1	$ 276.7	$ 278.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Nine Months Ended September 30, 2024 and 2023
(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, 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
Common Stock Dividends			(75.0)			(75.0)
Common Stock Dividends – Nonaffiliated					(0.3)	(0.3)
Net Income			157.5		1.5	159.0
Other Comprehensive Loss				(0.4)		(0.4)
TOTAL EQUITY – SEPTEMBER 30, 2023	$ 0.1	$ 1,492.2	$ 2,390.1	$ (4.9)	$ 1.3	$ 3,878.8
TOTAL EQUITY – DECEMBER 31, 2023	$ 0.1	$ 1,492.2	$ 2,281.3	$ (3.4)	$ 0.2	$ 3,770.4
Common Stock Dividends			(50.0)			(50.0)
Common Stock Dividends – Nonaffiliated					(1.4)	(1.4)
Net Income			208.1		1.5	209.6
Other Comprehensive Loss				(0.2)		(0.2)
TOTAL EQUITY – MARCH 31, 2024	0.1	1,492.2	2,439.4	(3.6)	0.3	3,928.4
Common Stock Dividends			(100.0)			(100.0)
Common Stock Dividends – Nonaffiliated					(1.0)	(1.0)
Net Income (Loss)			(70.1)		1.0	(69.1)
TOTAL EQUITY – JUNE 30, 2024	0.1	1,492.2	2,269.3	(3.6)	0.3	3,758.3
Return of Capital to Parent		(1.1)				(1.1)
Common Stock Dividends			(100.0)			(100.0)
Common Stock Dividends – Nonaffiliated					(1.0)	(1.0)
Net Income			139.1		1.0	140.1
Other Comprehensive Loss				(0.2)		(0.2)
TOTAL EQUITY – SEPTEMBER 30, 2024	$ 0.1	$ 1,491.1	$ 2,308.4	$ (3.8)	$ 0.3	$ 3,796.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
September 30, 2024 and December 31, 2023
(in millions)
(Unaudited)

	September 30, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4.4	$ 2.4
Advances to Affiliates	2.8	2.2
Accounts Receivable:		
Customers	27.5	39.0
Affiliated Companies	55.5	47.2
Miscellaneous	13.9	8.3
Total Accounts Receivable	96.9	94.5
Fuel	84.1	113.8
Materials and Supplies (September 30, 2024 and December 31, 2023 Amounts Include $2.7 and $3.9, Respectively, Related to Sabine)	87.0	88.4
Risk Management Assets	24.1	11.6
Accrued Tax Benefits	21.4	28.4
Regulatory Asset for Under-Recovered Fuel Costs	106.6	170.8
Prepayments and Other Current Assets	32.2	29.2
TOTAL CURRENT ASSETS	459.5	541.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,845.1	4,790.7
Transmission	2,754.8	2,660.6
Distribution	2,986.1	2,824.1
Other Property, Plant and Equipment (September 30, 2024 and December 31, 2023 Amounts Include $166.8 and $182.7, Respectively, Related to Sabine)	930.6	814.4
Construction Work in Progress	636.4	555.8
Total Property, Plant and Equipment	12,153.0	11,645.6
Accumulated Depreciation and Amortization (September 30, 2024 and December 31, 2023 Amounts Include $166.8 and $182.7, Respectively, Related to Sabine)	3,244.8	3,087.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,908.2	8,558.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,120.3	1,131.8
Deferred Charges and Other Noncurrent Assets	340.4	326.1
TOTAL OTHER NONCURRENT ASSETS	1,460.7	1,457.9
TOTAL ASSETS	$ 10,828.4	$ 10,557.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
September 30, 2024 and December 31, 2023
(Unaudited)

	September 30, 2024	December 31, 2023
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 237.4	$ 88.7
Accounts Payable:		
General	226.2	198.9
Affiliated Companies	49.3	45.9
Short-term Debt – Nonaffiliated	4.6	4.3
Customer Deposits	75.3	72.5
Accrued Taxes	116.8	58.7
Accrued Interest	38.8	39.9
Obligations Under Operating Leases	8.8	9.0
Provision for Refund	62.5	0.7
Other Current Liabilities	127.5	168.3
TOTAL CURRENT LIABILITIES	947.2	686.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,648.7	3,646.9
Deferred Income Taxes	1,260.4	1,179.3
Regulatory Liabilities and Deferred Investment Tax Credits	577.5	756.1
Asset Retirement Obligations	257.0	258.6
Employee Benefits and Pension Obligations	43.1	43.1
Obligations Under Operating Leases	119.5	122.5
Deferred Credits and Other Noncurrent Liabilities	178.9	93.8
TOTAL NONCURRENT LIABILITIES	6,085.1	6,100.3
TOTAL LIABILITIES	7,032.3	6,787.2
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	1,491.1	1,492.2
Retained Earnings	2,308.4	2,281.3
Accumulated Other Comprehensive Income (Loss)	(3.8)	(3.4)
TOTAL COMMON SHAREHOLDER’S EQUITY	3,795.8	3,770.2
Noncontrolling Interest	0.3	0.2
TOTAL EQUITY	3,796.1	3,770.4
TOTAL LIABILITIES AND EQUITY	$ 10,828.4	$ 10,557.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2024 and 2023
(in millions)
(Unaudited)

	Nine Months Ended September 30, 2024	2023
OPERATING ACTIVITIES		
Net Income	$ 280.6	$ 282.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	297.6	266.8
Deferred Income Taxes	(117.1)	44.9
Allowance for Equity Funds Used During Construction	(9.7)	(7.3)
Mark-to-Market of Risk Management Contracts	(23.3)	1.4
Property Taxes	(23.7)	(24.6)
Deferred Fuel Over/Under-Recovery, Net	134.3	134.4
Provision for Refund – Turk Plant	100.0	—
Change in Other Noncurrent Assets	(41.3)	(46.9)
Change in Other Noncurrent Liabilities	(46.0)	(26.7)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(2.4)	29.7
Fuel, Materials and Supplies	26.2	(12.0)
Accounts Payable	7.6	5.3
Accrued Taxes, Net	65.1	10.8
Provision for Refund – Turk Plant	60.0	—
Other Current Assets	(7.0)	10.4
Other Current Liabilities	(51.5)	(40.6)
Net Cash Flows from Operating Activities	649.4	627.7
INVESTING ACTIVITIES		
Construction Expenditures	(539.6)	(614.1)
Change in Advances to Affiliates, Net	(0.6)	(0.6)
Other Investing Activities	10.9	1.8
Net Cash Flows Used for Investing Activities	(529.3)	(612.9)
FINANCING ACTIVITIES		
Capital Contribution from Parent	—	50.0
Return of Capital to Parent	(1.1)	—
Issuance of Long-term Debt – Nonaffiliated	—	346.8
Change in Short-term Debt – Nonaffiliated	0.3	3.9
Change in Advances from Affiliates, Net	148.7	(261.8)
Retirement of Long-term Debt – Nonaffiliated	—	(94.1)
Principal Payments for Finance Lease Obligations	(13.0)	(17.6)
Dividends Paid on Common Stock	(250.0)	(125.0)
Dividends Paid on Common Stock – Nonaffiliated	(3.4)	(2.4)
Other Financing Activities	0.4	0.6
Net Cash Flows Used for Financing Activities	(118.1)	(99.6)
Net Increase (Decrease) in Cash and Cash Equivalents	2.0	(84.8)
Cash and Cash Equivalents at Beginning of Period	2.4	88.4
Cash and Cash Equivalents at End of Period	$ 4.4	$ 3.6
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 107.1	$ 89.8
Net Cash Paid (Received) for Income Taxes	(11.2)	(23.3)
Cash Paid (Received) for Transferable Tax Credits	(69.4)	—
Noncash Acquisitions Under Finance Leases	1.9	4.6
Construction Expenditures Included in Current Liabilities as of September 30,	84.9	69.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 108.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

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

1. SIGNIFICANT ACCOUNTING MATTERS

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

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three and nine months ended September 30, 2024 is not necessarily indicative of results that may be expected for the year ending December 31, 2024. The condensed financial statements are unaudited and should be read in conjunction with the audited 2023 financial statements and notes thereto, which are included in the Registrants' Annual Reports on Form 10-K as filed with the SEC on February 26, 2024.

Earnings Per Share (EPS) (Applies to AEP)

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

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

	Three Months Ended September 30,			
	2024		2023	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 959.6		$ 953.7	
Weighted-Average Number of Basic AEP Common Shares Outstanding	532.2	$ 1.80	520.5	$ 1.83
Weighted-Average Dilutive Effect of Stock-Based Awards	1.4	—	0.9	—
Weighted-Average Number of Diluted AEP Common Shares Outstanding	533.6	$ 1.80	521.4	$ 1.83

	Nine Months Ended September 30,			
	2024		2023	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 2,303.0		$ 1,871.9	
Weighted-Average Number of Basic AEP Common Shares Outstanding	529.2	$ 4.35	516.5	$ 3.62
Weighted-Average Dilutive Effect of Stock-Based Awards	1.3	(0.01)	1.3	—
Weighted-Average Number of Diluted AEP Common Shares Outstanding	530.5	$ 4.34	517.8	$ 3.62

There were no antidilutive shares outstanding as of September 30, 2024 and 2023, respectively.

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

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

Reconciliation of Cash, Cash Equivalents and Restricted Cash

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

	September 30, 2024		
	AEP	AEP Texas	APCo
		(in millions)	
Cash and Cash Equivalents	$ 245.8	$ 0.1	$ 6.5
Restricted Cash	53.4	45.1	8.3
Total Cash, Cash Equivalents and Restricted Cash	$ 299.2	$ 45.2	$ 14.8

	December 31, 2023		
	AEP	AEP Texas	APCo
		(in millions)	
Cash and Cash Equivalents	$ 330.1	$ 0.1	$ 5.0
Restricted Cash	48.9	34.0	14.9
Total Cash, Cash Equivalents and Restricted Cash	$ 379.0	$ 34.1	$ 19.9

Supplementary Cash Flow Information (Applies to AEP)

	Nine Months Ended September 30,	
Cash Flow Information	**2024**	**2023**
	(in millions)	
Cash Paid (Received) for:		
Interest, Net of Capitalized Amounts	$ 1,247.3	$ 1,148.7
Income Taxes	87.9	26.7
Sale of Transferable Tax Credits	(163.7)	—
Noncash Investing and Financing Activities:		
Acquisitions Under Finance Leases	24.5	38.5
Construction Expenditures Included in Current Liabilities as of September 30,	1,015.1	975.0
Acquisition of Nuclear Fuel Included in Current Liabilities as of September 30,	8.2	9.5
Noncash Increase in Noncurrent Assets from the Sale of the Competitive Contracted Renewables Portfolio	—	74.7

2. NEW ACCOUNTING STANDARDS

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

Management reviews the FASB's standard-setting process and the SEC's rulemaking activity to determine the relevance, if any, to the Registrants' business. The following standards/rules will impact the Registrants' financial statements.

SEC Climate Disclosure Rule

On March 6, 2024, the SEC adopted final rules that require registrants to disclose certain climate-related information in registration statements and annual reports. The final rules require registrants to disclose, among other things, material climate-related risks, activities to mitigate such risks and information about a registrant's board of directors oversight and management's role in managing material climate-related risks. The final rules also require registrants to provide information related to any climate-related targets or goals that are material to a registrant's business, results of operations or financial condition. A majority of the reporting requirements are applicable to the fiscal year beginning in 2025, with the addition of assurance reporting for GHG emissions starting in 2029 for large accelerated filers. Litigation challenging the new rules was filed by multiple parties in multiple jurisdictions, which have been consolidated and assigned to the U.S. Court of Appeals for the Eighth Circuit. On April 4, 2024, the SEC issued an order staying the final climate disclosure rules pending the completion of judicial review at the Court of Appeals. The Registrants are currently evaluating the impact of the final rules on their respective consolidated financial statements and related disclosures.

ASU 2023-07 "Improvements to Reportable Segment Disclosures" (ASU 2023-07)

In November 2023, the FASB issued ASU 2023-07, to address investors' observations that there is limited information disclosed about segment expenses and to better understand expense categories and amounts included in segment profit or loss. The new standard requires annual and interim disclosure of (a) the categories and amounts of significant segment expenses (determined by management using both qualitative and quantitative factors) that are regularly provided to the CODM and included within each reported measure of segment profit or loss, (b) the amounts and a qualitative description of "other segment items", defined as the difference between reported segment revenues less the significant segment expenses and each reported measure of segment profit or loss disclosed, (c) reportable segment profit or loss and assets that are currently only required annually, (d) the CODM's title and position, and an explanation of how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and deciding how to allocate resources and (e) a requirement that entities with a single reportable segment provide all disclosures required by ASU 2023-07 and all existing segment disclosures in Topic 280. Additionally, this new standard allows disclosure of one or more of additional profit or loss measures if the CODM uses more than one measure provided that at least one of the disclosed measures is determined in a manner "most consistent with the measurement principles under GAAP". If multiple measures are presented, additional disclosure is required about how the CODM uses each measure to assess performance and decide how to allocate resources.

The amendments in the new standard are effective on a retrospective basis for all entities for fiscal years beginning after December 15, 2023 and interim periods within fiscal periods beginning after December 15, 2024 with early adoption permitted. Management plans to adopt ASU 2023-07 effective for the 2024 10-K.

ASU 2023-09 "Improvements to Income Tax Disclosures" (ASU 2023-09)

In December 2023, the FASB issued ASU 2023-09, to address investors' suggested enhancements to (a) better understand an entity's exposure to potential changes in jurisdictional tax legislation and the ensuing risks and opportunities, (b) assess income tax information that affects cash flow forecasts and capital allocation decisions and (c) identify potential opportunities to increase future cash flows.

The new standard requires an annual rate reconciliation disclosure of the following categories regardless of materiality: state and local income tax, net of federal income tax effect, foreign tax effects, effect of changes in tax laws or rates enacted in the current period, effect of cross-border tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items and changes in unrecognized tax benefits.

The new standard also requires an annual disclosure of the amount of income taxes paid (net of refunds received) disaggregated by federal, state and foreign taxes and by individual jurisdictions that are equal to or greater than 5 percent of total income taxes paid. Disclosure of income (loss) from continuing operations before income tax expense (benefit) disaggregated between domestic and foreign jurisdictions and income tax expense (benefit) from continuing operations disaggregated by federal, state and foreign jurisdictions is required.

The new standard removes the requirement to disclose the cumulative amount of each type of temporary difference when a deferred tax liability is not recognized because of the exceptions to comprehensive recognition of deferred taxes related to subsidiaries and corporate joint ventures.

The amendments in the new standard may be applied on either a prospective or retrospective basis for public business entities for fiscal years beginning after December 15, 2024 with early adoption permitted. Management has not yet made a decision to early adopt the amendments to this standard or how to apply them.

ASU 2024-03 "Income Statement-Reporting Comprehensive Income-Expense Disaggregation Disclosures" (ASU 2024-03)

In November 2024, the FASB issued ASU 2024-03, the intent of which is to improve financial reporting and respond to investor input by requiring public business entities to disclose additional information about certain expenses in the notes to financial statements in interim and annual reporting periods. Among other provisions, the new standard requires disclosure of disaggregated amounts for expenses such as employee compensation, depreciation, and intangible asset amortization included in each expense caption presented on the face of the income statement. Public business entities are required to include certain amounts that are already required to be disclosed under GAAP in the same disclosure as the other disaggregation requirements as well as a qualitative description of any amounts remaining in relevant expense captions that are not separately disaggregated quantitatively. The new standard also requires disclosure of the total amount of selling expenses and, in annual reporting periods, an entity's definition of selling expenses. An entity is not precluded from providing additional voluntary disclosures that may provide investors with additional decision-useful information.

The amendments in the new standard are effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027, with early adoption permitted. The amendments in the new standard should be applied either prospectively to financial statements issued for reporting periods after the effective date or retrospectively to any or all prior periods presented in the financial statements. Management is evaluating the new standard and has not yet determined when, or the method by which, the Registrants will adopt its amendments.

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 September 30, 2024	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of June 30, 2024	$ 103.7	$ 9.3	$ (153.0)	$ (40.0)
Change in Fair Value Recognized in AOCI, Net of Tax	(28.8)	(24.5)	—	(53.3)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	0.1	—	—	0.1
Interest Expense (a)	—	8.8	—	8.8
Amortization of Prior Service Cost (Credit)	—	—	(1.4)	(1.4)
Amortization of Actuarial (Gains) Losses	—	—	0.7	0.7
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.1	8.8	(0.7)	8.2
Income Tax (Expense) Benefit	0.1	1.8	(0.1)	1.8
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—	7.0	(0.6)	6.4
Net Current Period Other Comprehensive Loss	(28.8)	(17.5)	(0.6)	(46.9)
Balance in AOCI as of September 30, 2024	$ 74.9	$ (8.2)	$ (153.6)	$ (86.9)

Three Months Ended September 30, 2023	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of June 30, 2023	$ 93.5	$ 12.7	$ (142.6)	$ (36.4)
Change in Fair Value Recognized in AOCI, Net of Tax	19.3	(6.9)	—	12.4
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(15.6)	—	—	(15.6)
Interest Expense (a)	—	(1.3)	—	(1.3)
Amortization of Prior Service Cost (Credit)	—	—	(5.3)	(5.3)
Amortization of Actuarial (Gains) Losses	—	—	1.3	1.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(15.6)	(1.3)	(4.0)	(20.9)
Income Tax (Expense) Benefit	(3.4)	(0.2)	(0.8)	(4.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(12.2)	(1.1)	(3.2)	(16.5)
Net Current Period Other Comprehensive Income (Loss)	7.1	(8.0)	(3.2)	(4.1)
Balance in AOCI as of September 30, 2023	$ 100.6	$ 4.7	$ (145.8)	$ (40.5)

Nine Months Ended September 30, 2024	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of December 31, 2023	$ 104.9	$ (8.1)	$ (152.3)	$ (55.5)
Change in Fair Value Recognized in AOCI, Net of Tax	(16.3)	(5.2)	—	(21.5)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(17.4)	—	—	(17.4)
Interest Expense (a)	—	6.5	—	6.5
Amortization of Prior Service Cost (Credit)	—	—	(4.0)	(4.0)
Amortization of Actuarial (Gains) Losses	—	—	2.4	2.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(17.4)	6.5	(1.6)	(12.5)
Income Tax (Expense) Benefit	(3.7)	1.4	(0.3)	(2.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(13.7)	5.1	(1.3)	(9.9)
Net Current Period Other Comprehensive Loss	(30.0)	(0.1)	(1.3)	(31.4)
Balance in AOCI as of September 30, 2024	$ 74.9	$ (8.2)	$ (153.6)	$ (86.9)

Nine Months Ended September 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	(170.1)	5.3	(12.9)	(177.7)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	59.7	—	—	59.7
Interest Expense (a)	—	(1.1)	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	—	(15.9)	(15.9)
Amortization of Actuarial (Gains) Losses	—	—	3.9	3.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	59.7	(1.1)	(12.0)	46.6
Income Tax (Expense) Benefit	12.5	(0.2)	(2.5)	9.8
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	47.2	(0.9)	(9.5)	36.8
Reclassifications of KPCo Pension and OPEB Regulatory Assets from AOCI, before Income Tax (Expense) Benefit	—	—	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)	(122.9)	4.4	(5.7)	(124.2)
Balance in AOCI as of September 30, 2023	$ 100.6	$ 4.7	$ (145.8)	$ (40.5)

(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 2023 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2023 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 2024 and updates the 2023 Annual Report.

Regulated Generating Units (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 in balance with reliability and other factors, which has resulted in, and in the future may result in, a proposal to retire 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. See the "2020 Texas Base Rate Case" section below for additional information. 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. In April 2024, the LPSC approved a unanimous settlement agreement filed by SWEPCo, LPSC staff and certain intervenors that resolved the prudency of the retirement of the Dolet Hills Power Station and resulted in a disallowance of $14 million in the first quarter of 2024.

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. In July 2023, Texas ALJs issued a PFD that concluded the decision to retire the Pirkey Plant was prudent. In September 2023, the PUCT rejected the ALJs' July 2023 PFD. In the open meeting, the commissioners expressed their concerns that the analysis in support of SWEPCo's decision to retire the Pirkey Plant was not robust enough and that SWEPCo should have re-evaluated the decision following Winter Storm Uri. The treatment of the cost of recovery of the Pirkey Plant is expected to be addressed in a future rate case. As of September 30, 2024, the Texas jurisdictional share of the net book value of the Pirkey Plant was $69 million. To the extent any portion of the Texas jurisdictional share of the net book value of the Pirkey Plant is not recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulated Generating Units to be Retired

PSO

In 2014, PSO received final approval from the Federal EPA to close Northeastern Plant, Unit 3, in 2026. The plant was originally scheduled to close in 2040. As a result of the early retirement date, PSO revised the useful life of Northeastern Plant, Unit 3, to the projected retirement date of 2026 and the incremental depreciation is being deferred as a regulatory asset. As ordered by the OCC, as part of the 2022 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 September 30, 2024, 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	$ 111.9	$ 181.2	$ 20.8 (b)	2026	(c)	$ 15.7
Welsh Plant, Units 1 and 3	341.4	156.7	57.6 (d)	2028 (e)	(f)	41.6

(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 September 30, 2024, SWEPCo's share of the net investment in the Dolet Hills Power Station was $76 million, including materials and supplies, net of cost of removal collected in rates. Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses and are subject to prudency determinations by the various commissions. After closure of the DHLC mining operations and the Dolet Hills Power Station, additional reclamation and other land-related costs incurred by DHLC and Oxbow will continue to be billed to SWEPCo and included in existing fuel clauses. As of September 30, 2024, SWEPCo had a net under-recovered fuel balance of $23 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 $35 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 up to $55 million, including denial of recovery of the $35 million deferral, with refunds to customers over five years. In February 2024, an ALJ issued a final recommendation which included a proposed $55 million refund to customers and the denial of recovery of the $35 million deferral. SWEPCo filed a motion to present oral arguments with the LPSC to dispute the ALJ's recommendations. In April 2024, the LPSC approved a unanimous settlement agreement filed by SWEPCo, LPSC staff and certain intervenors that resolved the fuel recovery dispute and resulted in a fuel disallowance of $11 million. The remaining $24 million regulatory asset balance will be recovered over three years with interest.

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 September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of $48 million of Oxbow mine related costs through 2035.

If any of these costs are not recoverable or customer refunds are required, 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 September 30, 2024, SWEPCo's share of the net investment in the Pirkey Plant was $187 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 September 30, 2024, SWEPCo had a net under-recovered fuel balance of $23 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 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. The LPSC established a procedural schedule stating staff and intervenor testimony is due in November 2024 and a hearing is scheduled for March 2025.

In September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of $33 million of Sabine related fuel costs through 2035.

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

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

	AEP	
	September 30, 2024	**December 31, 2023**
Noncurrent Regulatory Assets	**(in millions)**	
Regulatory Assets Currently Earning a Return		
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 156.7	$ 125.6
Pirkey Plant Accelerated Depreciation	120.8	114.4
Unrecovered Winter Storm Fuel Costs (a)	75.9	97.2
Storm-Related Costs	41.3	—
Other Regulatory Assets Pending Final Regulatory Approval	16.2	49.8
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	379.5	408.9
Plant Retirement Costs – Asset Retirement Obligation Costs (b)	340.4	25.9
NOLC Costs (c)	82.9	—
2024-2025 Virginia Biennial Under-Earnings	18.6	—
Other Regulatory Assets Pending Final Regulatory Approval	51.3	52.6
Total Regulatory Assets Pending Final Regulatory Approval	$ 1,283.6	$ 874.4

(a) Includes $37 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of September 30, 2024 and December 31, 2023, respectively. See the "February 2021 Severe Winter Weather Impacts in SPP" section below for additional information.

(b) See "Federal EPA's Revised CCR Rule" section of Note 5 for additional information.

(c) In the second quarter of 2024, requests seeking to establish a recovery mechanism for these regulatory assets were filed in Indiana, Oklahoma and Texas. In Indiana and Oklahoma, certain intervenors have challenged the recovery, or have proposed ratemaking treatment that would offset the recovery, of the regulatory assets. In the third quarter of 2024, PUCT Staff and certain intervenors in Texas requested a hearing and direct testimony was filed by SWEPCo in October 2024.

Noncurrent Regulatory Assets	AEP Texas	
	September 30, 2024	December 31, 2023
	(in millions)	
Regulatory Assets Currently Earning a Return		
Storm-Related Costs	$ 41.3	$ —
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	16.6	37.7
Line Inspection Costs	5.8	5.7
Vegetation Management Program	—	5.2
Texas Retail Electric Provider Bad Debt Expense	—	4.0
Other Regulatory Assets Pending Final Regulatory Approval	1.4	11.7
Total Regulatory Assets Pending Final Regulatory Approval	$ 65.1	$ 64.3

Noncurrent Regulatory Assets	APCo	
	September 30, 2024	December 31, 2023
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 1.0	$ 0.6
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs (a)	266.9	25.9
Storm-Related Costs – West Virginia	126.5	91.5
2024-2025 Virginia Biennial Under-Earnings	18.6	—
Other Regulatory Assets Pending Final Regulatory Approval	14.7	7.5
Total Regulatory Assets Pending Final Regulatory Approval	$ 427.7	$ 125.5

(a) See "Federal EPA's Revised CCR Rule" section of Note 5 for additional information.

Noncurrent Regulatory Assets	I&M	
	September 30, 2024	December 31, 2023
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 2.3	$ 0.2
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs (a)	72.9	—
NOLC Costs – Indiana (b)	24.6	—
Storm-Related Costs – Indiana	7.4	29.7
Other Regulatory Assets Pending Final Regulatory Approval	4.4	3.3
Total Regulatory Assets Pending Final Regulatory Approval	$ 111.6	$ 33.2

(a) See "Federal EPA's Revised CCR Rule" section of Note 5 for additional information.

(b) In the second quarter of 2024, a request seeking to establish a recovery mechanism for these regulatory assets were filed in Indiana. Certain intervenors have challenged the recovery, or have proposed ratemaking treatment that would offset the recovery, of the regulatory assets.

Noncurrent Regulatory Assets	OPCo September 30, 2024	OPCo December 31, 2023
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.2	$ —
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	—	23.6
Other Regulatory Assets Pending Final Regulatory Approval	0.1	—
Total Regulatory Assets Pending Final Regulatory Approval	$ 0.3	$ 23.6

Noncurrent Regulatory Assets	PSO September 30, 2024	PSO December 31, 2023
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 94.2	$ 88.5
NOLC Costs (a)	14.2	—
Other Regulatory Assets Pending Final Regulatory Approval	3.2	0.2
Total Regulatory Assets Pending Final Regulatory Approval	$ 111.6	$ 88.7

(a) In the second quarter of 2024, a request seeking to establish a recovery mechanism for these regulatory assets were filed in Oklahoma. Certain intervenors have challenged the recovery, or have proposed ratemaking treatment that would offset the recovery, of the regulatory assets.

Noncurrent Regulatory Assets	SWEPCo September 30, 2024	SWEPCo December 31, 2023
	(in millions)	
Regulatory Assets Currently Earning a Return		
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 156.7	$ 125.6
Pirkey Plant Accelerated Depreciation	120.8	114.4
Unrecovered Winter Storm Fuel Costs (a)	75.9	97.2
Dolet Hills Power Station Accelerated Depreciation (b)	11.8	12.0
Other Regulatory Assets Pending Final Regulatory Approval	1.0	26.0
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs - Louisiana, Texas	49.0	56.0
NOLC Costs (c)	44.1	—
Other Regulatory Assets Pending Final Regulatory Approval	18.5	13.7
Total Regulatory Assets Pending Final Regulatory Approval	$ 477.8	$ 444.9

(a) Includes $37 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of September 30, 2024 and December 31, 2023, respectively. See the "February 2021 Severe Winter Weather Impacts in SPP" section below for additional information.
(b) Amounts include the FERC jurisdiction.
(c) In the second quarter of 2024, a request seeking to establish a recovery mechanism for the Texas jurisdictional share of these regulatory assets were filed in Texas. In the third quarter of 2024, PUCT Staff and certain intervenors in Texas requested a hearing and direct testimony was filed by SWEPCo in October 2024.

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

AEP Texas Rate Matters (Applies to AEP and AEP Texas)

2024 AEP Texas Base Rate Case

In February 2024, AEP Texas filed a request with the PUCT for a $164 million annual base rate increase over its adjusted test year revenues which include interim transmission and distribution rate updates. AEP Texas's request is based upon a proposed 10.6% ROE with a capital structure of 55% debt and 45% common equity. The rate case seeks a prudence determination on all capital additions placed in service during the period January 1, 2019 through September 30, 2023. As of September 30, 2024, AEP Texas' cumulative revenues from transmission and distribution interim rate increases are estimated to be approximately $1.3 billion and are subject to reconciliation in this base rate case. In July 2024, AEP Texas filed an unopposed settlement agreement with the PUCT. The settlement agreement included a proposed annual revenue increase of $70 million based upon a 9.76% ROE with a capital structure of 57.5% debt and 42.5% common equity. In addition, the settlement agreement approved the prudency of capital investments placed in service for the period January 1, 2019 through September 30, 2023 and the associated interim revenues collected on those capital investments. In October 2024, the PUCT issued a final order approving the settlement agreement without modification.

APCo and WPCo Rate Matters (Applies to AEP and APCo)

ENEC (Expanded Net Energy Cost) Filings

In January 2024, the WVPSC issued an order resolving APCo's and WPCo's (the Companies) 2021-2023 ENEC cases. In the order, the WVPSC: (a) disallowed $232 million in ENEC under-recovered costs as of February 28, 2023 ($136 million related to APCo) and (b) approved the recovery of $321 million of ENEC under-recovered costs as of February 28, 2023 ($174 million related to APCo) plus a 4% debt carrying charge rate over a ten-year recovery period starting September 1, 2024. In February 2024, the Companies filed briefs with the West Virginia Supreme Court to initiate an appeal of this order. In September 2024, oral arguments were held at the West Virginia Supreme Court. A final ruling is expected in the fourth quarter of 2024.

In April 2024, the Companies submitted their annual ENEC update filing with the WVPSC proposing a $58 million annual increase in ENEC rates when compared to existing ENEC rates. The Companies proposed that this ENEC rate change would: (a) become effective September 1, 2024, (b) include a $20 million annual increase in ENEC rates related to the period ending February 29, 2024 and the forecast period September 2024 through August 2025 and (c) include a $38 million annual increase in ENEC rates for the recovery of $321 million of ENEC under-recovered costs as of February 28, 2023 over a ten-year period, plus a 4% debt carrying charge rate. In July 2024, intervenors and staff filed testimony with the WVPSC, which did not recommend any disallowances.

In August 2024, the WVPSC issued an order approving the requested $38 million annual increase effective September 1, 2024. The WVPSC will address the proposed additional $20 million annual increase in ENEC rates in a future order. If any costs included in the future filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

Virginia Fuel Adjustment Clause (FAC) Review

In 2023, APCo submitted its annual fuel cost filing with the Virginia SCC. Interim Virginia FAC rates were implemented in November 2023. In APCo's 2022 Virginia fuel update filing, the Virginia staff ordered the Virginia Staff to commence an audit of APCo's fuel costs for the years ended December 31, 2019, 2020, 2021 and 2022. The Virginia staff analyzed APCo's 2019 through 2022 fuel procurement activities and concluded the procurement practices were reasonable and prudent and recommended no disallowances. In May 2024, the Virginia SCC issued an order approving the audit of APCo's 2019 and 2020 fuel costs but concluded that the review of APCo fuel costs for 2021 and 2022 remains open for further evaluation. As of September 30, 2024, APCo had a Virginia jurisdictional under-recovered fuel balance of $164 million. If any fuel costs are not recoverable or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

2024 Virginia Base Rate Case

In March 2024, APCo filed a request with the Virginia SCC for a $95 million annual increase in base rates based upon a proposed 10.8% ROE and a proposed capital structure of 51% debt and 49% common equity. The requested increase in base rates is primarily due to incremental rate base, proposed capital structure changes including an increase in ROE and proposed increases in distribution and generation operation and maintenance expenses. In September 2024, a hearing was held where APCo updated its requested increase in base rates to $64 million consistent with its rebuttal positions or, alternatively, an increase of $45 million if annual environmental compliance consumable expenses are moved from base rates to recovery through APCo's environmental rate adjustment clause. An order will be issued in the fourth quarter of 2024. If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

2024 West Virginia Base Rate Case

In November 2024, APCo and WPCo (the Companies) filed a request with the WVPSC for a net $251 million annual increase in base rates based upon a proposed 10.8% ROE and a proposed capital structure of 52% debt and 48% common equity. The requested net annual increase in base rates excludes the Companies' proposed $94 million annual Modified Rate Base Cost (MRBC) surcharge update proposed to be effective in a separate proceeding and the existing $21 million annual Mitchell Base Rate Surcharge that are both proposed to be rolled into base rates upon the Companies' anticipated 2025 change in base rates. The Companies' proposed base rate increase includes recovery of approximately $118 million in previously deferred major storm expense over a three-year period, capital structure changes including an increase in ROE, an increase in depreciation expense related to proposed changes in depreciation rates and increased capital investments and increases in distribution and generation operation and maintenance expenses.

The Companies' November 2024 West Virginia base rate filing also included two sets of alternative frameworks to simplify rates and customer bills and provide predictable future rate increases. The Companies' first framework includes: (a) securitization, (b) approval of a major storm expense recovery and tracking mechanism and (c) freezing of OATT revenues in the ENEC. This framework includes securitization in a concurrent proceeding of approximately $2.4 billion of West Virginia jurisdictional assets including: (a) the Companies' remaining combined unrecovered ENEC balance related to costs incurred through February 28, 2023, (b) undepreciated West Virginia jurisdictional plant balances as of December 31, 2022 for the Amos, Mitchell and Mountaineer Plants, (c) environmental costs previously approved for recovery through a separate West Virginia surcharge and (d) deferred major storm operation and maintenance costs. Securitization of those items could reduce the Companies' combined requested increase in annual base rates to $37 million.

The Companies also included an alternative ratemaking proposal that includes: (a) a separate surcharge that would allow the Companies up to a 3% annual increase in overall West Virginia rates for four consecutive years on April 1st of each year after the implementation of base rates in this case, (b) the elimination of all of the Companies' existing West Virginia jurisdictional surcharges except for the ENEC, with the revenues of these eliminated riders rolled into base rates and (c) the creation of a new West Virginia jurisdictional environmental and new generation surcharge. This alternative proposal would allow the Companies to submit a base rate case filing in advance of and in lieu of the annual April 1st 3% increase and would require the Companies to submit a base rate case filing at the end of the proposed four-year period.

If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

West Virginia Modified Rate Base Cost (MRBC) Surcharge Update Filing

In March 2024, APCo and WPCo (the Companies) submitted an annual MRBC surcharge update filing with the WVPSC requesting a $32 million annual increase in the Companies' combined MRBC rates. The MRBC is an infrastructure investment tracker that allows limited cost recovery related to capital investments between the Companies' West Virginia jurisdictional base rate cases. WVPSC staff and an intervening party recommended revenue requirement disallowances in written and verbal testimony and briefs for certain ratemaking issues used to develop the Companies' proposed MRBC rates, including the West Virginia jurisdictional effect of state deferred income taxes, NOLC and AROs. If any refund liabilities are imposed by the WVPSC, it could reduce future net income and cash flows and impact financial condition.

Hurricane Helene

In late September 2024, the remnants of Hurricane Helene significantly impacted APCo's Virginia and West Virginia service territories leading to approximately 260,000 customer outages and damages to APCo's power grid. Storm restoration efforts continued into early October and APCo completed restoration efforts for all customers who lost power by October 6th, 2024. As of September 30, 2024, APCo incurred approximately $19 million ($13 million related to the Virginia jurisdiction and $6 million related to the West Virginia jurisdiction) of incremental other operation and maintenance expenses and approximately $8 million of capital expenditures. APCo deferred $16 million of the incremental other operation and maintenance expenses as regulatory assets as the costs are deemed probable of future recovery. Based on the information currently available, APCo estimates total storm restoration costs to be approximately $140 million, of which 70% is expected to be deferred as regulatory assets and the remaining 30% of the costs are expected to be capital expenditures. If any costs related to Hurricane Helene are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next base rate proceeding. Through September 30, 2024, AEP's share of ETT's cumulative revenues that are subject to a prudency review is approximately $1.8 billion. A base rate review could produce a refund to customers 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 $1.8 billion of cumulative revenues above will be subject to review.

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

2023 Michigan Power Supply Cost Recovery (PSCR) Reconciliation

In March 2024, I&M submitted its 2023 PSCR Reconciliation to the MPSC. In October 2024, MPSC staff and intervenors submitted testimony recommending PSCR cost disallowances associated with the OVEC Inter-Company Power Agreement and the Rockport UPA with AEGCo ranging from $3 million to $15 million. A hearing is scheduled for December 2024. If any PSCR costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2023 Indiana Base Rate Case

In August 2023, I&M filed a request with the IURC for a $116 million annual increase in Indiana base rates based upon a 2024 forecasted test year, a proposed 10.5% ROE and a proposed capital structure of 48.8% debt and 51.2% common equity. I&M proposed that the annual increase in base rates be implemented in two steps, with the first increase effective in mid-2024, following an IURC order, and the second increase effective in January 2025. The proposed annual increase includes, but is not limited to, a $41 million increase related to depreciation expense, driven by increased depreciation rates and increased capital investments, and a $15 million increase related to storm expenses. I&M's Indiana base case filing requested recovery of certain historical period regulatory asset balances and proposed deferral accounting for certain future investments and tax related issues, including CAMT expense and PTCs related to the Cook Plant.

In December 2023, I&M and intervenors reached a settlement agreement that was submitted to the IURC recommending a two-step increase in Indiana rates with a $28 million annual increase effective upon an IURC order and the remaining $34 million annual increase effective in January 2025 subject to I&M's level of electric plant in service as of December 31, 2024 in comparison to I&M's 2024 forecasted test year. The recommended revenue increase includes: (a) a 9.85% ROE, (b) a two-step update of I&M's Indiana capital structure with a capital structure of 50% for both debt and common equity effective upon an IURC order and a January 2025 update based on I&M's actual capital structure as of December 31, 2024 with common equity not to exceed 51.2%, (c) a $25 million increase related to depreciation expense and (d) an $11 million increase related to storm expenses. In addition, I&M also agreed to withdraw its proposal to defer CAMT and Cook Plant PTCs and to instead include the Indiana jurisdictional impact of Cook Plant PTCs in I&M's Indiana earnings test evaluations. See "Indiana Earnings Test" below for additional information.

In May 2024, the IURC issued an order approving the settlement agreement with minor modifications.

2023 Michigan Base Rate Case

In September 2023, I&M filed a request with the MPSC for a $34 million annual increase in Michigan base rates based upon a 2024 forecasted test year, a proposed 10.5% ROE and a capital structure of 49.4% debt and 50.6% common equity. The proposed annual increase includes an $11 million annual increase in depreciation expense driven by increased capital investment. I&M's Michigan base case filing requests recovery of certain historical period regulatory asset balances and proposes deferral accounting for certain future investments and tax related issues, including CAMT expense and PTCs related to the Cook Plant.

In July 2024, the MPSC issued a final order approving an annual base rate increase of $17 million based on a 9.86% ROE and a capital structure of 52% debt and 48% common equity. The MPSC also ordered that Michigan jurisdictional Cook Plant PTCs will be reflected as a deferral in I&M's PSCR reconciliation and rejected I&M's request to defer Michigan jurisdictional CAMT.

Indiana Earnings Test

I&M is required by Indiana law to submit an earnings test evaluation for the most recent one-year and five-year periods as part of I&M's semi-annual Indiana FAC filings. These earnings test evaluations require I&M to include a credit in the FAC factor computation for periods in which I&M earned above its authorized return for both the one-year and five-year periods. The credit is determined as 50% of the lower of the one-year or five-year earnings above the authorized level. In July 2024, I&M submitted its FAC filing and earnings test evaluation for the period ended May 2024. In September 2024, an intervenor submitted testimony suggesting that I&M failed to prorate calculations of I&M's operating income and I&M's earnings test ceiling to reflect the impact of I&M's updated Indiana base rates that became effective in May 2024. The IURC is expected to issue an order in November 2024. As of September 30, 2024, I&M's financial statements adequately reflect the estimated impact of upcoming Indiana earnings test filings, including Indiana's jurisdictional share of PTCs that have been recognized in 2024. If the IURC issues orders on I&M's Indiana earnings test(s) that result in refunds to customers, it could reduce future net income and cash flows and impact financial condition.

KPCo Rate Matters (Applies to AEP)

Investigation of the Service, Rates and Facilities of KPCo

In June 2023, 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. In December 2023 and February 2024, KPCo and certain intervenors filed testimony with the KPSC. A hearing with the KPSC was previously scheduled to occur in June 2024. The hearing was postponed and has not yet been rescheduled. If any fines or penalties are levied against KPCo relating to the show cause order, it could 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. In conjunction with its June 2023 filing, KPCo further requested to finance through the issuance of securitization bonds, approximately $471 million of regulatory assets. KPCo's proposal did not address the disposition of its 50% interest in Mitchell Plant, which will be addressed in the future. As of September 30, 2024, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $552 million. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

In November 2023, KPCo filed an uncontested settlement agreement with the KPSC, that included an annual base rate increase of $75 million, based upon a 9.75% ROE. Settlement parties agreed that the KPSC should approve KPCo's securitization request, and that the approximately $471 million regulatory assets requested for securitization are comprised of prudently incurred costs.

In January 2024, the KPSC issued an order modifying the November 2023 uncontested settlement agreement and approving an annual base rate increase of $60 million based upon a 9.75% ROE effective with billing cycles mid-January 2024. The order reduced KPCo's base rate revenue requirement by $14 million to allow recovery of actual test year PJM transmission costs instead of KPCo's requested annual level of costs based on PJM 2023 projected transmission revenue requirements. In February 2024, KPCo filed an appeal with the Commonwealth of Kentucky Franklin Circuit Court, challenging among other aspects of the order, the $14 million base rate revenue requirement reduction.

In January 2024, consistent with the November 2023 uncontested settlement agreement, the KPSC issued a financing order approving KPCo's request to securitize certain regulatory assets balances as of the time securitization bonds are issued and concluding that costs requested for recovery through securitization were prudently incurred. The KPSC's financing order includes certain additional requirements related to securitization bond structuring, marketing, placement and issuance that were not reflected in KPCo's proposal. In accordance with Kentucky statutory requirements and the financing order, the issuance of the securitized bonds is subject to final review by the KPSC after bond pricing. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the first half of 2025, subject to market conditions. As of September 30, 2024, regulatory asset balances expected to be recovered through securitization total $485 million and include: (a) $297 million of plant retirement costs, (b) $79 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, (c) $49 million of deferred purchased power expenses, (d) $58 million of under-recovered purchased power rider costs and (e) $2 million of deferred issuance-related expenses, including KPSC advisor expenses. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Fuel Adjustment Clause (FAC) Review

In December 2023, KPCo received intervenor testimony in its FAC review for the two-year period ending October 31, 2022, recommending a disallowance ranging from $44 million to $60 million of its total $432 million purchased power cost recoveries as a result of proposed modifications to the ratemaking methodology that limits purchased power costs recoverable through the FAC. A hearing was held in February 2024 and the KPSC may issue its order in the fourth quarter of 2024 or early 2025. If any fuel costs are not recoverable or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

Rockport Offset Recovery

In January 2024, KPCo filed an application with the KPSC seeking to recover an allowed cost (Rockport Offset) of $41 million in accordance with the terms of the settlement agreement in the 2017 Kentucky Base Rate Case permitting KPCo to use the level of non-fuel, non-environmental Rockport Plant UPA expense included in base rates to earn its authorized ROE in 2023 since the Rockport UPA ended in December 2022. An estimated Rockport Offset of $23 million was recovered through a rider, subject to true-up, during the 12-months ended December 2023. In February 2024, the KPSC issued an order allowing KPCo to collect the remaining $18 million through interim rates, subject to refund, over twelve months starting in March 2024. In April 2024, KPCo submitted to the KPSC a request for decision on the record. In August 2024, KPCo filed an application with the KPSC to extend the recovery of the remaining balance through September 2025. The KPSC may issue its order in the fourth quarter of 2024 or early 2025. Through the third quarter of 2024, the Rockport Offset true-up is reflected in revenues to the extent amounts have been billed to customers, as KPCo has not met the requirements of alternative revenue recognition in accordance with the accounting guidance for "Regulated Operations". If the Rockport Offset is not recoverable or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

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

OVEC Cost Recovery Audits

In December 2021, as part of OVEC cost recovery audits pending before the PUCO, intervenors filed positions claiming that costs incurred by 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 May 2023, as part of the OVEC cost recovery audits pending before the PUCO, intervenors filed positions claiming that costs incurred by OPCo during the 2020 audit period were imprudent and should be disallowed.

In August 2024, the PUCO issued orders pertaining to the OVEC cost recovery audits that: (a) denied intervenors' application for rehearing on the 2016-2017 audit period, (b) determined costs incurred by OPCo during the 2018-2019 audit period were prudent, (c) determined costs incurred by OPCo during the 2020 audit period were prudent and (d) recommended no disallowances for any mentioned audit period in question. In September 2024, intervenors filed for rehearing on the 2018-2019 and 2020 OVEC cost recovery audit periods claiming the PUCO's August 2024 orders to adopt the findings of the audit reports were unjust, unlawful and unreasonable for multiple reasons, including the position that OPCo recovered imprudently incurred costs. In October 2024, the PUCO denied the intervenors' applications for rehearing of the 2018-2019 and 2020 audit periods.

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 DIR, 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. In September 2023, OPCo and certain intervenors filed a settlement agreement with the PUCO addressing the ESP application. The settlement included a four year term from June 2024 through May 2028, an ROE of 9.7% and continuation of a number of riders including the DIR subject to revenue caps. In April 2024, the PUCO issued an order approving the settlement agreement. In May 2024, intervenors filed an application for rehearing with the PUCO on the approved settlement agreement and the PUCO denied the intervenors' application for rehearing in June 2024.

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

2024 Oklahoma Base Rate Case

In January 2024, PSO filed a request with the OCC for a $218 million annual base rate increase based upon a 10.8% ROE with a capital structure of 48.9% debt and 51.1% common equity. PSO requested an expanded transmission cost recovery rider and a mechanism to recover generation costs necessary to comply with SPP's 2023 increased capacity planning reserve margin requirements. PSO's request includes the 155 MW Rock Falls Wind Facility and reflects recovery of Northeastern Plant, Unit 3 through 2040.

In July 2024, OCC staff and various intervenors filed testimony. The OCC staff recommended a $115 million annual base rate increase based upon a 9.3% ROE while intervenors recommended an annual base rate increase ranging from $19 million to $113 million based on an ROE ranging from 9.0% to 9.6%. The OCC staff also recommended a $62 million disallowance of certain capital investments. In addition, a certain intervenor recommended the OCC reject PSO's request to recover the Rock Falls Wind Facility through base rates, but allow PSO to retain PTCs and energy revenues up to the Rock Falls Wind Facility annual revenue requirement. In September 2024, the OCC staff withdrew its recommendation for a $62 million disallowance of certain capital investments.

In October 2024, PSO, the OCC and certain intervenors filed a joint stipulation and settlement agreement with the OCC that included a net annual revenue increase of $120 million based upon a 9.5% ROE with a capital structure of 48.9% debt and 51.1% common equity. The agreement also allows for Rock Falls Wind Facility to be included in base rates and the deferral of certain generation-related costs necessary to comply with SPP's 2023 increased capacity reserve margin requirements. One intervenor opposed the joint stipulation and settlement agreement. In October 2024, a hearing was held at the OCC, and PSO implemented an interim annual base rate increase of $120 million, subject to refund pending a final order by the OCC. An order is expected in the fourth quarter of 2024. If any costs included in this filing are not approved for recovery, it could 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. In November 2021, SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court. 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. In October 2023, SWEPCo filed testimony with the PUCT in the remanded proceeding recommending no refund or disallowance.

In December 2023, the PUCT approved a preliminary order stating the PUCT will not address SWEPCo's request that would allow the PUCT to find cause to allow SWEPCo to exceed the Texas jurisdictional capital cost cap in the current remand proceeding. As a result of the PUCT's approval of the preliminary order, SWEPCo recorded a pretax, non-cash disallowance of $86 million in the fourth quarter of 2023.

The PUCT's December 2023 approval of the preliminary order determined that it will address, in the ongoing PUCT remand proceeding, any potential revenue refunds to customers that may be required by future PUCT orders. On March 1, 2024, SWEPCo filed supplemental direct testimony with the PUCT in response to the December 2023 preliminary order. On March 8, 2024, intervenors and the PUCT staff filed a motion with the PUCT to strike portions of SWEPCo's October 2023 direct testimony and March 2024 supplemental direct testimony. On March 19, 2024, the ALJ granted portions of the motion, which included removal of testimony supporting SWEPCo's position that refunds were not appropriate. On March 28, 2024, SWEPCo filed an appeal of the ALJ decision with the PUCT. In April 2024, intervenors and PUCT staff submitted testimony recommending customer refunds through December 2023 ranging from $149 million to $197 million, including carrying charges, with refund periods ranging from 18 months to 48 months. In May 2024, the PUCT denied SWEPCo's appeal of the ALJ's March 2024 decision. In the second quarter of 2024, based on the PUCT's decision, SWEPCo recorded a one-time, probable revenue refund provision of $160 million, including interest, associated with revenue collected from February 2013 through December 2023. In June 2024, SWEPCo and parties to the remand proceeding reached an agreement in principle that would resolve all issues in the case. In October 2024, SWEPCo filed the settlement agreement with the PUCT. Under the settlement agreement, SWEPCo will refund over a two-year period $148 million, including interest, associated with revenue collected from February 2013 through December 2023 and remove AFUDC in excess of the Texas jurisdictional capital cost cap from rate base. The settlement is expected to be considered by the PUCT in the fourth quarter of 2024.

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 9.6% ROE, 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. 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 judicial review of the several errors challenged in the PUCT's final order.

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% through March 2024. In April 2023, the LPSC issued an order approving the stipulation and settlement agreement. In July 2023, SWEPCo submitted additional information in phase two of this proceeding to obtain a financing order and prudency review of capital investment. In April 2024, SWEPCo and the LPSC staff filed a joint uncontested stipulation and settlement agreement with the LPSC requesting securitization of storm costs, including a storm reserve. In July 2024, the LPSC issued an order approving the joint uncontested stipulation and settlement agreement, including approval to securitize $343 million, which includes $180 million for storm costs and a $150 million storm reserve. Securitization bonds are expected to be issued in the fourth quarter of 2024, subject to market conditions.

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	September 30, 2024	December 31, 2023	Approved Recovery Period	Approved Carrying Charge
	(in millions)			
Arkansas	$ 40.4	$ 54.2	6 years	(a)
Louisiana	75.9	97.2	(b)	(b)
Texas	79.3	101.9	5 years	1.65%
Total	$ 195.6	$ 253.3		

(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. In August 2024, the APSC issued an order that found SWEPCo had prudently incurred these costs.

(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.

PSO and SWEPCo Rate Matters (Applies to AEP, PSO and SWEPCo)

North Central Wind Energy Facilities

The NCWF are subject to various regulatory performance requirements, including a Net Capacity Factor (NCF) guarantee. The NCF guarantee will be measured in MWhs across all facilities on a combined basis for each five year period for the first thirty full years of operation. The first NCF guarantee five year period began in April 2022. Certain wind turbines have experienced performance issues related to defects covered by the manufacturer's warranty. These performance issues have prompted PSO and SWEPCo to file a lawsuit against the manufacturer in an attempt to find a resolution on the matter. If regulatory performance requirements, such as the NCF guarantee, are not met, PSO and SWEPCo may recognize a regulatory liability to refund retail customers. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

FERC Rate Matters

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 as to state law claims. In December 2023, the United States District Court for the Middle District of Pennsylvania granted summary judgment in favor of Transource Energy, finding that the PAPUC decision violated federal law and the United States Constitution. In January 2024, the PAPUC filed an appeal of the district court's grant of summary judgment with the United States Court of Appeals for the Third Circuit. Additional regulatory proceedings before the PAPUC are expected to resume in 2025.

In September 2021, PJM notified Transource Energy that the IEC was suspended to allow for the regulatory and related appeals process to proceed in an orderly manner without breaching milestone dates in the project agreement. At that time, PJM stated that the IEC has not been cancelled and remains necessary to alleviate congestion. PJM continues to evaluate reliability and market efficiency in the area. As of September 30, 2024, AEP's share of IEC capital expenditures was approximately $94 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.

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 the UPA between AEGCo and 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. In August 2023, AEGCo reached a settlement agreement with the FERC trial staff that resolved all issues set for hearing. In September 2023, the settlement agreement was certified to the FERC as uncontested. In March 2024, the FERC issued an order approving the uncontested settlement agreement. The results of the order did not have a material impact on financial condition, results of operations or cash flows.

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

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 2024, 2023, 2022 and 2021 by $52 million, $61 million, $69 million and $78 million, respectively.

In January 2024, the FERC issued two orders granting formal challenges by certain unaffiliated customers related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. Accordingly, in the third quarter of 2024, the AEP transmission owning subsidiaries within SPP provided a portion of the 2021 rate year refunds, with the remainder of the refunds expected to be provided in 2025. The AEP transmission owning subsidiaries within PJM are expected to provide their respective refunds for the 2021 rate year in 2025. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests for rehearing. In March 2024, the FERC denied AEPSC's requests for rehearing of the January 2024 orders by operation of law and stated it may address the requests for rehearing in future orders. In March 2024, AEPSC submitted refund compliance reports to the FERC, which preserve the non-finality of the FERC's January 2024 orders pending further proceedings on rehearing and appeal. In April 2024, AEPSC made filings with the FERC which request that the FERC: (a) reopen the record so that the FERC may take the IRS PLRs received in April 2024 regarding the treatment of stand-alone NOLCs in ratemaking into evidence and consider them in substantive orders on rehearing and (b) stay its January 2024 orders and related compliance filings and refunds to provide time for consideration of the April 2024 IRS PLRs. In May 2024, AEPSC filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit seeking review of the FERC's January 2024 and March 2024 decisions. In July 2024, the FERC issued orders approving AEPSC's request to reopen the record for the limited purpose of accepting into the record the IRS PLRs and establish additional briefing procedures. In August 2024, AEPSC filed briefs with the FERC requesting the commission modify or overturn their initial orders.

As a result of the January 2024 FERC orders, the Registrants' balance sheets reflect a liability for the probable refund of all NOLC revenues included in transmission formula rates for years 2024, 2023, 2022 and 2021, with interest. The Registrants have not yet been directed to make cash refunds related to the 2024, 2023 or 2022 rate years. The probable refunds to affiliated and nonaffiliated customers are reflected as Deferred Credits and Other Noncurrent Liabilities on the balance sheets, with the exception of amounts expected to be refunded within one year which are reflected in Other Current Liabilities. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Regulatory Liabilities or a reduction to Regulatory Assets on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms.

Request to Update SWEPCo Generation Depreciation Rates (Applies to AEP and SWEPCo)

In October 2023, SWEPCo filed an application to revise its generation wholesale customer's contracts to reflect an increase in the annual revenue requirement of approximately $5 million for updated depreciation rates and allow for the return on and of FERC customers jurisdictional share of regulatory assets associated with retired plants. In November 2023, certain intervenors filed a motion with the FERC protesting and recommending the rejection of SWEPCo's filings. In December 2023, the FERC issued an order approving the proposed rates effective January 1, 2024, subject to further review and refund and established hearing and settlement proceedings. If SWEPCo is unable to recover the remaining regulatory assets associated with retired plants, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2023 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.

In March 2024, AEP increased its $4 billion revolving credit facility to $5 billion and extended the due date from March 2027 to March 2029. Also, in March 2024, AEP extended the due date of its $1 billion revolving credit facility from March 2025 to March 2027. AEP may issue up to $1.2 billion as letters of credit under these revolving credit facilities on behalf of subsidiaries. As of September 30, 2024, no letters of credit were issued under either 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 September 30, 2024 were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 236.3	October 2024 to July 2025
AEP Texas	1.8	July 2025

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2024, there were no material liabilities recorded for any indemnifications.

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

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of September 30, 2024, 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	$ 42.8
AEP Texas	9.9
APCo	5.5
I&M	4.0
OPCo	6.9
PSO	4.1
SWEPCo	4.9

ENVIRONMENTAL CONTINGENCIES (Applies to all Registrants except AEPTCo)

Federal EPA's Revised CCR Rule

In April 2024, the Federal EPA finalized 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"). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all of the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. Closure may be accomplished by applying an impermeable cover system over the CCR material ("closure in place") or the CCR material may be excavated and placed in a compliant landfill ("closure by removal"). Groundwater monitoring and other analysis over the next three years will provide additional information on the planned closure method. AEP evaluated the applicability of the rule to current and former plant sites and recorded incremental ARO in the second quarter of 2024, as shown in the table below, based on initial cost estimates primarily reflecting compliance with the rule through closure in place and future groundwater monitoring requirements pursuant to the CCR Rule.

Registrant	Increase in ARO	Increase in Generation Property (a)	Increase in Regulatory Assets (b)	Charged to Operating Expenses (c)
		(in millions)		
APCo	$ 312.2	$ 75.6	$ 236.6	$ —
I&M	85.7	—	72.3	13.4
OPCo	52.9	—	—	52.9
PSO	33.7	33.7	—	—
SWEPCo	23.8	23.8	—	—
Non-Registrants	166.1	43.8	46.1	76.2
Total	$ 674.4	$ 176.9	$ 355.0	$ 142.5

(a) ARO is related to a legacy CCR surface impoundment or CCR management unit at an operating generation facility.
(b) ARO is related to a legacy CCR surface impoundment or CCR management unit at a retired generation facility and recognition of a regulatory asset in accordance with the accounting guidance for "Regulated Operations" is supported.
(c) ARO is related to a legacy CCR surface impoundment or CCR management unit and recognition of a regulatory asset in accordance with the accounting guidance for "Regulated Operations" is not yet supported.

As further groundwater monitoring and other analysis is performed, management expects to refine the assumptions and underlying cost estimates used in recording the ARO. These refinements may include, but are not limited to, changes in the expected method of closure, changes in estimated quantities of CCR at each site, the identification of new CCR management units, among other items. These future changes could have a material impact on the ARO and materially reduce future net income and cash flows and further impact financial condition.

AEP will seek cost recovery through regulated rates, including proposal of new regulatory mechanisms for cost recovery where existing mechanisms are not applicable. The rule could have an additional, material adverse impact on net income, cash flows and financial condition if AEP cannot ultimately recover these additional costs of compliance. Several parties, including AEP and one of its trade associations, have filed petitions for review of the rule with the U.S. Court of Appeals for the D.C. Circuit. One of the parties also filed a motion to stay the rule pending the outcome of the litigation. In November 2024, the court denied the stay motion. Management cannot predict the outcome of the litigation.

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. Management is currently evaluating applying for license extensions for both units. 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

Insurance and Potential Losses

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

Insurance coverage for certain claims made by third-parties is structured to reimburse the Registrants for the amounts they are legally obligated to pay in excess of the Registrants' retentions. Such claims, when deemed probable of occurring and reasonably estimable, are reflected as liabilities on the financial statements of the Registrants. Also, when it is deemed probable that these claims, or any portion thereof, will be covered by insurance or otherwise reimbursable to the Registrant, an asset is recognized on the balance sheet. As of September 30, 2024, AEP Texas recorded an Accrued Litigation Settlement within current liabilities and a corresponding Insurance Receivable within current assets on the balance sheet related to an injured contractor claim.

In July 2024, the Registrants renewed insurance programs including coverage for wildfire liability. Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cybersecurity incident, extreme weather or wildfire related liabilities or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered through rate-making process, could reduce future net income and cash flows and impact financial condition.

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

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 (collectively, the "Derivative Actions") 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 in April 2022. In June 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. In September 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. In January 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. In March 2023, the federal district court issued an order granting the motion to dismiss with prejudice and denying the New York plaintiffs' motion to intervene. In April 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.

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 letter from counsel representing the purported AEP shareholder who had 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). The Litigation Demand is directed to the AEP Board and contains factual allegations involving HB 6 that are generally consistent with those in the Derivative Actions. The Litigation Demand requested, 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 asserting claims similar to the claims asserted in the Derivative Actions. The AEP Board considered the Litigation Demand and formed a committee of the Board (the Demand Review Committee) to investigate, review, monitor and analyze the Litigation Demand and make a recommendation to the AEP Board regarding a reasonable and appropriate response to the same.

In April 2024, AEP reached an agreement with the four shareholders to fully and finally resolve the Derivative Actions and the Litigation Demand, and all claims asserted or that could have been asserted by any AEP shareholder based on the facts alleged, in the manner and upon the terms and conditions set forth in the settlement documents (the Settlement). In July 2024, the U.S. District Court preliminarily approved the Settlement. The Settlement includes a payment of $450 thousand for attorneys' fees and the implementation of certain governance changes outlined in the Settlement, many of which have already been put in place. The Settlement does not include any admission of liability. In October 2024, the District Court issued an Order and

Judgment approving the Settlement and granted an Order of Dismissal with Prejudice. Under the Settlement, all Derivative Actions have been or will be dismissed, the Litigation Demand has been withdrawn, and those matters and claims have been resolved pursuant to the terms of the Settlement.

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. AEP and the SEC are engaged in discussions about a possible resolution of the SEC's investigation and potential claims under the securities laws. Based on these discussions, in the third quarter of 2024, AEP recorded a loss contingency of $19 million in Other Operation expenses on AEP's statements of income and accrued a corresponding liability in Other Current Liabilities on AEP's balance sheets. A resolution of the investigation or claims may subject AEP to civil penalties in an amount that could differ from the amount recorded; however, management does not believe any such resolution would be material.

Claims for Indemnification Made by Owners of the Gavin Power Station (Applies to AEP)

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 assertions related to the CCR Rule (see "Environmental Issues - CCR Rule" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information), including an assertion 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 any determinations of noncompliance by the Federal EPA with various aspects of the CCR Rule consistent with 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, which in June 2024, were dismissed for lack of jurisdiction. In January 2024, Gavin Power LLC also filed a complaint with the United States District Court for the Southern District of Ohio, alleging various violations of the Administrative Procedure Act and asserting that the Federal EPA, through its prior inaction, has waived and is estopped from raising certain objections raised in the Gavin Denial. Management cannot predict the outcome of that litigation. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

Litigation Regarding Justice Thermal Coal Contract (Applies to AEP and APCo)

In December 2023, APCo filed a suit in the Franklin County Ohio Court of Common Pleas seeking a declaratory judgment confirming APCo's right to terminate a long-term coal contract with Justice Thermal LLC (Justice Thermal) based on Justice Thermal's failure to perform under the contract. APCo terminated that contract in January 2024, and in April 2024, APCo filed an amended complaint seeking a declaration that the termination was proper and also seeking damages for Justice Thermal's breach of contract. Justice Thermal filed an answer and counterclaim in April 2024, contesting the validity of the contract termination and asserting counterclaims. The parties entered into a Settlement Agreement and Release pursuant to which the litigation was dismissed with prejudice in September 2024 and each party released the other from all claims relating to the contract or the litigation, and as a result this matter has been resolved.

6. ACQUISITIONS AND DISPOSITIONS

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

ACQUISITIONS

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," AEP management determined that the acquisition of the Rock Falls Wind Facility represents an asset acquisition. The lease obligations related to Rock Falls were not material at the time of acquisition.

DISPOSITIONS

Disposition of AEP OnSite Partners (Generation & Marketing Segment) (Applies to AEP)

In April 2023, AEP initiated a sales process for its ownership in AEP OnSite Partners. 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. In May 2024, AEP signed an agreement to sell AEP OnSite Partners to a nonaffiliated third-party. In September 2024, AEP completed the sale to a nonaffiliated third-party and received cash proceeds of approximately $318 million, net of taxes and transaction costs. The proceeds were used to pay down short-term debt.

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 (the portfolio) within the Generation & Marketing segment. 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 portfolio and AEP signed an agreement with a nonaffiliated party. 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 and determining the carrying value of the portfolio exceeded the estimated fair value.

In August 2023, AEP completed the sale of the entire portfolio to the nonaffiliated party and received cash proceeds of approximately $1.2 billion, net of taxes and transaction costs.

Disposition of NMRD (Generation & Marketing Segment) (Applies to AEP)

In December 2023, AEP and the joint owner signed an agreement to sell NMRD to a nonaffiliated third party and the sale was completed in February 2024. AEP received cash proceeds of approximately $107 million, net of taxes and transaction costs. The transaction did not have a material impact on net income or financial condition.

7. BENEFIT PLANS

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

AEPSC sponsors a qualified pension plan and two unfunded non-qualified pension plans. Substantially all AEP subsidiary employees are covered by the qualified plan or both the qualified and a non-qualified pension plan. AEPSC 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 September 30, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 25.6	$ 2.3	$ 2.4	$ 3.3	$ 2.3	$ 1.5	$ 1.9
Interest Cost	51.9	4.4	6.2	5.9	4.8	2.5	3.1
Expected Return on Plan Assets	(80.2)	(6.5)	(10.7)	(10.7)	(8.2)	(4.3)	(4.4)
Amortization of Net Actuarial Loss	1.0	—	0.1	0.1	0.1	—	0.1
Net Periodic Benefit Cost (Credit) (a)	$ (1.7)	$ 0.2	$ (2.0)	$ (1.4)	$ (1.0)	$ (0.3)	$ 0.7

Three Months Ended September 30, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 23.6	$ 2.1	$ 2.3	$ 2.9	$ 2.1	$ 1.4	$ 2.0
Interest Cost	54.8	4.5	6.6	6.3	5.0	2.7	3.4
Expected Return on Plan Assets	(84.8)	(7.0)	(11.2)	(11.0)	(8.6)	(4.6)	(4.8)
Amortization of Net Actuarial Loss	0.3	—	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	$ (6.1)	$ (0.4)	$ (2.3)	$ (1.8)	$ (1.5)	$ (0.5)	$ 0.6

Nine Months Ended September 30, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 76.8	$ 6.7	$ 7.3	$ 9.9	$ 7.0	$ 4.6	$ 5.9
Interest Cost	155.7	13.1	18.6	17.8	14.2	7.5	9.3
Expected Return on Plan Assets	(240.6)	(19.5)	(32.1)	(32.1)	(24.5)	(13.0)	(13.2)
Amortization of Net Actuarial Loss	3.2	0.2	0.3	0.3	0.2	0.1	0.2
Net Periodic Benefit Cost (Credit) (a)	$ (4.9)	$ 0.5	$ (5.9)	$ (4.1)	$ (3.1)	$ (0.8)	$ 2.2

Nine Months Ended September 30, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 70.8	$ 6.2	$ 6.8	$ 8.9	$ 6.3	$ 4.2	$ 5.8
Interest Cost	164.4	13.7	19.8	18.7	14.9	8.1	10.4
Expected Return on Plan Assets	(254.4)	(21.0)	(33.5)	(33.1)	(25.6)	(13.8)	(14.5)
Amortization of Net Actuarial Loss	1.0	—	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	$ (18.2)	$ (1.1)	$ (6.9)	$ (5.5)	$ (4.4)	$ (1.5)	$ 1.7

(a) Excludes an immaterial settlement amount to a non-qualified pension plan in the second quarter of 2024 for AEP. Management continues to monitor settlements under the qualified pension plan as a result of the voluntary severance program announced in the second quarter of 2024. See Note 13 - Voluntary Severance Program for additional information.

OPEB

Three Months Ended September 30, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1.1	$ —	$ 0.2	$ 0.1	$ —	$ 0.1	$ 0.1
Interest Cost	10.3	0.9	1.7	1.2	1.1	0.6	0.7
Expected Return on Plan Assets	(27.8)	(2.3)	(4.1)	(3.4)	(3.0)	(1.5)	(1.9)
Amortization of Prior Service Credit	(3.1)	(0.3)	(0.5)	(0.4)	(0.3)	(0.2)	(0.3)
Amortization of Net Actuarial Loss	0.8	0.1	0.1	0.1	0.1	—	0.1
Net Periodic Benefit Credit (a)	$ (18.7)	$ (1.6)	$ (2.6)	$ (2.4)	$ (2.1)	$ (1.0)	$ (1.3)

Three Months Ended September 30, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ —
Interest Cost	11.6	0.9	1.8	1.3	1.2	0.6	0.8
Expected Return on Plan Assets	(27.4)	(2.2)	(4.0)	(3.3)	(2.9)	(1.5)	(1.8)
Amortization of Prior Service Credit	(15.8)	(1.3)	(2.3)	(2.2)	(1.6)	(1.0)	(1.3)
Amortization of Net Actuarial Loss	3.7	0.3	0.6	0.5	0.4	0.2	0.3
Net Periodic Benefit Credit	$ (26.8)	$ (2.2)	$ (3.8)	$ (3.6)	$ (2.8)	$ (1.6)	$ (2.0)

Nine Months Ended September 30, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 3.3	$ 0.2	$ 0.4	$ 0.4	$ 0.2	$ 0.2	$ 0.3
Interest Cost	31.4	2.5	5.0	3.6	3.2	1.7	2.0
Expected Return on Plan Assets	(83.5)	(6.8)	(12.2)	(10.1)	(8.9)	(4.5)	(5.6)
Amortization of Prior Service Credit	(9.5)	(0.8)	(1.4)	(1.3)	(0.9)	(0.6)	(0.8)
Amortization of Net Actuarial Loss	2.3	0.2	0.3	0.3	0.3	0.1	0.2
Net Periodic Benefit Credit (a)	$ (56.0)	$ (4.7)	$ (7.9)	$ (7.1)	$ (6.1)	$ (3.1)	$ (3.9)

Nine Months Ended September 30, 2023	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 3.4	$ 0.3	$ 0.4	$ 0.5	$ 0.3	$ 0.2	$ 0.2
Interest Cost	34.7	2.7	5.5	4.0	3.5	1.8	2.2
Expected Return on Plan Assets	(82.2)	(6.7)	(12.0)	(10.1)	(8.8)	(4.4)	(5.4)
Amortization of Prior Service Credit	(47.3)	(4.0)	(6.9)	(6.5)	(4.7)	(3.0)	(3.7)
Amortization of Net Actuarial Loss	11.1	0.9	1.7	1.4	1.2	0.6	0.8
Net Periodic Benefit Credit	$ (80.3)	$ (6.8)	$ (11.3)	$ (10.7)	$ (8.5)	$ (4.8)	$ (5.9)

(a) Excludes an immaterial amount related to special termination benefits resulting from the voluntary severance program announced in the second quarter of 2024. See Note 13 - Voluntary Severance Program for additional information.

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

- Marketing, risk management and retail activities in ERCOT, MISO, PJM and SPP.
- Competitive generation in PJM.

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

AEP's CODM makes operating decisions, allocates resources to and assesses performance based on these operating segments. AEP measures segment profit or loss based on net income (loss). Net income (loss) includes intercompany revenues and expenses that are eliminated on the Consolidated Financial Statements. In addition, direct interest expense and income taxes are included in net income (loss).

The tables below represent AEP's reportable segment income statement information for the three and nine months ended September 30, 2024 and 2023 and reportable segment balance sheet information as of September 30, 2024 and December 31, 2023.

	Three Months Ended September 30, 2024						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 3,248.8	$ 1,568.5	$ 113.1	$ 483.7	$ 6.0	$ —	$ 5,420.1
Other Operating Segments	54.2	6.9	399.4	15.4	32.1	(508.0) (b)	—
Total Revenues	$ 3,303.0	$ 1,575.4	$ 512.5	$ 499.1	$ 38.1	$ (508.0)	$ 5,420.1
Net Income (Loss)	$ 572.5	$ 245.2	$ 215.8	$ 93.3	$ (165.1)	$ —	$ 961.7

	Three Months Ended September 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	$ 3,158.1	$ 1,535.2	$ 94.0	$ 527.5	$ 26.9	$ —	$ 5,341.7
Other Operating Segments	47.3	8.9	382.7	39.2	30.3	(508.4) (b)	—
Total Revenues	$ 3,205.4	$ 1,544.1	$ 476.7	$ 566.7	$ 57.2	$ (508.4)	$ 5,341.7
Net Income (Loss)	$ 514.0	$ 206.0	$ 203.9	$ 132.8	$ (98.4)	$ —	$ 958.3

	Nine Months Ended September 30, 2024						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 8,722.0	$ 4,480.5	$ 332.3	$ 1,442.1	$ 48.1	$ —	$ 15,025.0
Other Operating Segments	147.9	21.0	1,167.4	88.0	100.5	(1,524.8) (b)	—
Total Revenues	$ 8,869.9	$ 4,501.5	$ 1,499.7	$ 1,530.1	$ 148.6	$ (1,524.8)	$ 15,025.0
Net Income (Loss)	$ 1,201.5	$ 542.3	$ 627.5	$ 226.1	$ (287.5)	$ —	$ 2,309.9

	Nine Months Ended September 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	$ 8,603.4	$ 4,321.3	$ 272.4	$ 1,172.6	$ 35.4	$ —	$ 14,405.1
Other Operating Segments	134.3	27.2	1,118.4	52.5	83.9	(1,416.3) (b)	—
Total Revenues	$ 8,737.7	$ 4,348.5	$ 1,390.8	$ 1,225.1	$ 119.3	$ (1,416.3)	$ 14,405.1
Net Income (Loss)	$ 1,054.6	$ 508.4	$ 583.6	$ (62.2)	$ (209.6)	$ —	$ 1,874.8

	September 30, 2024						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Assets	$ 53,723.0	$ 26,102.6	$ 17,490.1	$ 1,725.2	$ 4,393.7 (c)	$ (3,315.5) (d)	$ 100,119.1

	December 31, 2023						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
	(in millions)						
Total Assets	$ 51,802.1	$ 24,838.4	$ 16,575.6	$ 2,598.5	$ 5,194.0 (c)	$ (4,324.6) (d)	$ 96,684.0

(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 and interest expense, income tax expense and other nonallocated costs.
(b) Represents inter-segment revenues.
(c) Includes elimination of Parent's investments in wholly-owned subsidiary companies.
(d) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.

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

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

AEPTCo's Reportable Segments

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

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

The tables below present AEPTCo's reportable segment income statement information for the three and nine months ended September 30, 2024 and 2023 and reportable segment balance sheet information as of September 30, 2024 and December 31, 2023.

	Three Months Ended September 30, 2024			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
		(in millions)		
Revenues from:				
External Customers	$ 101.1	$ —	$ —	$ 101.1
Sales to AEP Affiliates	395.9	—	—	395.9
Other Revenues	0.2	—	—	0.2
Total Revenues	$ 497.2	$ —	$ —	$ 497.2
Net Income	$ 190.8	$ 0.5 (a)	$ —	$ 191.3

	Three Months Ended September 30, 2023			
	State Transcos	**AEPTCo Parent**	**Reconciling Adjustments**	**AEPTCo Consolidated**
		(in millions)		
Revenues from:				
External Customers	$ 92.8	$ —	$ —	$ 92.8
Sales to AEP Affiliates	369.9	—	—	369.9
Total Revenues	$ 462.7	$ —	$ —	$ 462.7
Net Income	$ 178.2	$ 1.0 (a)	$ —	$ 179.2

	Nine Months Ended September 30, 2024			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 295.1	$ —	$ —	$ 295.1
Sales to AEP Affiliates	1,157.1	—	—	1,157.1
Other Revenues	3.0	—	—	3.0
Total Revenues	$ 1,455.2	$ —	$ —	$ 1,455.2
Net Income	$ 547.7	$ 0.5 (a)	$ —	$ 548.2

	Nine Months Ended September 30, 2023			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 269.2	$ —	$ —	$ 269.2
Sales to AEP Affiliates	1,080.0	—	—	1,080.0
Total Revenues	$ 1,349.2	$ —	$ —	$ 1,349.2
Net Income	$ 514.0	$ 3.6 (a)	$ —	$ 517.6

	September 30, 2024			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets	$ 15,972.9	$ 5,938.9 (b)	$ (6,017.5) (c)	$ 15,894.3

	December 31, 2023			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets	$ 15,120.6	$ 5,486.6 (b)	$ (5,534.7) (c)	$ 15,072.5

(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. DERIVATIVES AND HEDGING

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

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of certain AEP subsidiaries, including the Registrant Subsidiaries. AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Notional Volume of Derivative Instruments

	September 30, 2024							December 31, 2023						
Primary Risk Exposure	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
								(in millions)						
Commodity:														
Power (MWhs)	306.0	—	38.6	8.5	2.1	7.0	6.5	246.8	—	16.8	5.9	2.2	4.1	2.9
Natural Gas (MMBtus)	161.5	—	47.1	—	—	36.4	14.7	151.6	—	37.3	—	—	34.9	17.9
Heating Oil and Gasoline (Gallons)	7.2	1.7	0.9	1.6	1.1	0.7	0.8	6.5	1.8	1.0	0.6	1.2	0.7	0.9
Interest Rate (USD)	$ 59.3	$ —	$ —	$ —	$ —	$ —	$ —	$ 80.1	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt (USD)	$1,750.0	$ —	$ —	$ —	$ —	$400.0	$ —	$1,300.0	$150.0	$ —	$ —	$ —	$ —	$ —

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 $44 million and $46 million as of September 30, 2024 and December 31, 2023, 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 September 30, 2024 and December 31, 2023. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was not material for the Registrants as of September 30, 2024 and December 31, 2023.

Location and Fair Value of Derivative Assets and Liabilities Recognized In the Balance Sheet

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets. The derivative instruments are disclosed as gross. They 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." 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.

	September 30, 2024						
	AEP	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
Assets:				(in millions)			
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 444.4	$ —	$ 54.4	$ 22.7	$ —	$ 28.7	$ 24.6
Hedging Contracts - Commodity	41.2	—	—	—	—	—	—
Hedging Contracts - Interest Rate	—	—	—	—	—	—	—
Total Current Risk Management Assets	485.6	—	54.4	22.7	—	28.7	24.6
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	448.3	—	0.8	—	—	0.6	—
Hedging Contracts - Commodity	63.3	—	—	—	—	—	—
Hedging Contracts - Interest Rate	—	—	—	—	—	—	—
Total Long-term Risk Management Assets	511.6	—	0.8	—	—	0.6	—
Total Assets	$ 997.2	$ —	$ 55.2	$ 22.7	$ —	$ 29.3	$ 24.6
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 334.9	$ 0.5	$ 15.9	$ 1.5	$ 6.6	$ 11.9	$ 5.6
Hedging Contracts - Commodity	6.7	—	—	—	—	—	—
Hedging Contracts - Interest Rate	51.7	—	—	—	—	10.9	—
Total Current Risk Management Liabilities	393.3	0.5	15.9	1.5	6.6	22.8	5.6
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	391.1	0.1	6.7	0.1	45.4	0.6	—
Hedging Contracts - Commodity	2.9	—	—	—	—	—	—
Hedging Contracts - Interest Rate	40.9	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	434.9	0.1	6.7	0.1	45.4	0.6	—
Total Liabilities	$ 828.2	$ 0.6	$ 22.6	$ 1.6	$ 52.0	$ 23.4	$ 5.6
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 169.0	$ (0.6)	$ 32.6	$ 21.1	$ (52.0)	$ 5.9	$ 19.0

	December 31, 2023						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Assets:							
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 555.1	$ —	$ 24.6	$ 30.1	$ —	$ 19.7	$ 12.0
Hedging Contracts - Commodity	56.7	—	—	—	—	—	—
Hedging Contracts - Interest Rate	—	—	—	—	—	—	—
Total Current Risk Management Assets	611.8	—	24.6	30.1	—	19.7	12.0
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	468.8	—	0.3	12.0	—	—	0.5
Hedging Contracts - Commodity	86.8	—	—	—	—	—	—
Hedging Contracts - Interest Rate	—	—	—	—	—	—	—
Total Long-term Risk Management Assets	555.6	—	0.3	12.0	—	—	0.5
Total Assets	$ 1,167.4	$ —	$ 24.9	$ 42.1	$ —	$ 19.7	$ 12.5
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 588.0	$ 0.2	$ 18.5	$ 5.4	$ 6.9	$ 29.7	$ 14.9
Hedging Contracts - Commodity	8.2	—	—	—	—	—	—
Hedging Contracts - Interest Rate	50.5	2.7	—	—	—	—	—
Total Current Risk Management Liabilities	646.7	2.9	18.5	5.4	6.9	29.7	14.9
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	377.6	—	6.9	0.2	43.9	1.0	1.7
Hedging Contracts - Commodity	2.2	—	—	—	—	—	—
Hedging Contracts - Interest Rate	56.9	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	436.7	—	6.9	0.2	43.9	1.0	1.7
Total Liabilities	$ 1,083.4	$ 2.9	$ 25.4	$ 5.6	$ 50.8	$ 30.7	$ 16.6
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 84.0	$ (2.9)	$ (0.5)	$ 36.5	$ (50.8)	$ (11.0)	$ (4.1)

Offsetting Assets and Liabilities

The following tables show the net amounts of assets and liabilities presented on the balance sheets. The gross amounts offset include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with accounting guidance for "Derivatives and Hedging." All derivative contracts subject to a master netting arrangement or similar agreement are offset on the balance sheets.

	September 30, 2024						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:				(in millions)			
Current Risk Management Assets							
Gross Amounts Recognized	$ 485.6	$ —	$ 54.4	$ 22.7	$ —	$ 28.7	$ 24.6
Gross Amounts Offset	(248.9)	—	(7.3)	(1.0)	—	(0.3)	(0.5)
Net Amounts Presented	236.7	—	47.1	21.7	—	28.4	24.1
Long-term Risk Management Assets							
Gross Amounts Recognized	511.6	—	0.8	—	—	0.6	—
Gross Amounts Offset	(253.3)	—	(0.8)	—	—	(0.5)	—
Net Amounts Presented	258.3	—	—	—	—	0.1	—
Total Assets	$ 495.0	$ —	$ 47.1	$ 21.7	$ —	$ 28.5	$ 24.1
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 393.3	$ 0.5	$ 15.9	$ 1.5	$ 6.6	$ 22.8	$ 5.6
Gross Amounts Offset	(241.3)	(0.5)	(8.3)	(1.2)	(0.3)	(0.5)	(0.8)
Net Amounts Presented	152.0	—	7.6	0.3	6.3	22.3	4.8
Long-term Risk Management Liabilities							
Gross Amounts Recognized	434.9	0.1	6.7	0.1	45.4	0.6	—
Gross Amounts Offset	(233.3)	(0.1)	(0.8)	—	(0.1)	(0.5)	—
Net Amounts Presented	201.6	—	5.9	0.1	45.3	0.1	—
Total Liabilities	$ 353.6	$ —	$ 13.5	$ 0.4	$ 51.6	$ 22.4	$ 4.8
Total MTM Derivative Contract Net Assets (Liabilities)	$ 141.4	$ —	$ 33.6	$ 21.3	$ (51.6)	$ 6.1	$ 19.3

	December 31, 2023						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:				(in millions)			
Current Risk Management Assets							
Gross Amounts Recognized	$ 611.8	$ —	$ 24.6	$ 30.1	$ —	$ 19.7	$ 12.0
Gross Amounts Offset	(394.3)	—	(2.2)	(2.3)	—	(0.7)	(0.4)
Net Amounts Presented	217.5	—	22.4	27.8	—	19.0	11.6
Long-term Risk Management Assets							
Gross Amounts Recognized	555.6	—	0.3	12.0	—	—	0.5
Gross Amounts Offset	(234.4)	—	(0.3)	(0.2)	—	—	(0.5)
Net Amounts Presented	321.2	—	—	11.8	—	—	—
Total Assets	$ 538.7	$ —	$ 22.4	$ 39.6	$ —	$ 19.0	$ 11.6
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 646.7	$ 2.9	$ 18.5	$ 5.4	$ 6.9	$ 29.7	$ 14.9
Gross Amounts Offset	(417.1)	(0.2)	(2.6)	(3.4)	(0.1)	(0.8)	(0.5)
Net Amounts Presented	229.6	2.7	15.9	2.0	6.8	28.9	14.4
Long-term Risk Management Liabilities							
Gross Amounts Recognized	436.7	—	6.9	0.2	43.9	1.0	1.7
Gross Amounts Offset	(194.9)	—	(0.3)	(0.2)	—	—	(0.5)
Net Amounts Presented	241.8	—	6.6	—	43.9	1.0	1.2
Total Liabilities	$ 471.4	$ 2.7	$ 22.5	$ 2.0	$ 50.7	$ 29.9	$ 15.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 67.3	$ (2.7)	$ (0.1)	$ 37.6	$ (50.7)	$ (10.9)	$ (4.0)

The tables below present the Registrants' amount of gain (loss) recognized on risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

	Three Months Ended September 30, 2024						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
	(in millions)						
Vertically Integrated Utilities Revenues	$ (1.1)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(67.1)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	(1.2)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	0.7	—	0.5	—	—	—	—
Other Operation	(0.3)	(0.1)	—	(0.1)	—	—	—
Maintenance	(0.5)	(0.1)	(0.1)	(0.1)	(0.1)	—	(0.1)
Regulatory Assets (a)	3.1	(0.6)	(3.9)	—	(9.2)	11.6	6.5
Regulatory Liabilities (a)	60.8	—	9.8	2.9	—	23.8	21.8
Total Gain (Loss) on Risk Management Contracts	$ (4.4)	$ (0.8)	$ 6.4	$ 1.5	$ (9.3)	$ 35.4	$ 28.2

	Three Months Ended September 30, 2023						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
	(in millions)						
Vertically Integrated Utilities Revenues	$ (9.5)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(1.4)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	(9.6)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	0.2	—	0.2	—	—	—	—
Maintenance	(0.4)	(0.1)	(0.1)	—	(0.1)	(0.1)	(0.1)
Regulatory Assets (a)	1.2	0.5	1.2	1.7	0.5	(3.5)	(1.1)
Regulatory Liabilities (a)	43.0	0.4	11.9	1.6	—	12.9	12.7
Total Gain (Loss) on Risk Management Contracts	$ 33.1	$ 0.8	$ 13.3	$ (6.3)	$ 0.4	$ 9.3	$ 11.5

Location of Gain (Loss)	Nine Months Ended September 30, 2024 AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Vertically Integrated Utilities Revenues	$ (22.5)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(164.8)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.2	(22.7)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	2.4	—	2.1	0.1	—	—	—
Maintenance	0.1	—	—	—	—	—	—
Regulatory Assets (a)	48.3	(0.3)	11.2	3.0	(3.7)	19.3	11.6
Regulatory Liabilities (a)	206.0	—	35.5	12.2	—	75.9	71.4
Total Gain (Loss) on Risk Management Contracts	$ 69.5	$ (0.3)	$ 49.0	$ (7.4)	$ (3.7)	$ 95.2	$ 83.0

Location of Gain (Loss)	Nine Months Ended September 30, 2023 AEP	AEP Texas	APCo	I&M (in millions)	OPCo	PSO	SWEPCo
Vertically Integrated Utilities Revenues	$ 2.2	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(290.6)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	2.1	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	2.2	—	2.1	0.1	—	—	—
Other Operation	(0.1)	—	—	—	—	—	—
Maintenance	(0.6)	(0.2)	(0.1)	—	(0.1)	(0.1)	(0.1)
Regulatory Assets (a)	(36.0)	—	—	(0.4)	(24.6)	(7.0)	(3.5)
Regulatory Liabilities (a)	143.5	0.4	3.1	6.4	—	73.3	58.2
Total Gain (Loss) on Risk Management Contracts	$ (179.4)	$ 0.2	$ 5.2	$ 8.2	$ (24.7)	$ 66.2	$ 54.6

(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	
	September 30, 2024	**December 31, 2023**	**September 30, 2024**	**December 31, 2023**
		(in millions)		
Long-term Debt (a) (b)	$ (890.1)	$ (878.2)	$ 57.5	$ 68.4

(a) Amounts included within Noncurrent Liabilities line item Long-term Debt on the Balance Sheet.
(b) Amounts include $(24) million and $(30) million as of September 30, 2024 and December 31, 2023, respectively, for the fair value hedge adjustment of hedged debt obligations for which hedge accounting has been discontinued.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	**2023**	**2024**	**2023**
		(in millions)		
Gain (Loss) on Interest Rate Contracts:				
Fair Value Hedging Instruments (a)	$ 14.8	$ (13.4)	$ 16.7	$ (10.7)
Fair Value Portion of Long-term Debt (a)	(14.8)	13.4	(16.7)	10.7

(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, Fuel and Other Consumables Used for Electric Generation on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2024 and 2023, 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 September 30, 2024, AEP and PSO applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the three months ended September 30, 2023, the Registrants did not apply cash flow hedging to outstanding interest rate derivatives. During the nine months ended September 30, 2024, AEP, AEP Texas and PSO applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not. During the nine months ended September 30, 2023, AEP, AEP Texas, I&M, PSO and SWEPCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

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

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

Impact of Cash Flow Hedges on the Registrants' Balance Sheets

	September 30, 2024				December 31, 2023			
	AOCI Gain (Loss) Net of Tax		Portion Expected to be Reclassed to Net Income During the Next Twelve Months		AOCI Gain (Loss) Net of Tax		Portion Expected to be Reclassed to Net Income During the Next Twelve Months	
	Commodity	Interest Rate	Commodity	Interest Rate	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)							
AEP	$ 74.9	$ (8.2)	$ 27.3	$ 2.9	$ 104.9	$ (8.1)	$ 38.3	$ 3.2
AEP Texas	—	6.5	—	0.7	—	0.5	—	0.2
APCo	—	5.3	—	0.8	—	5.9	—	0.8
I&M	—	(5.2)	—	(0.4)	—	(5.5)	—	(0.4)
PSO	—	(8.8)	—	(0.6)	—	(0.2)	—	—
SWEPCo	—	1.1	—	0.3	—	1.3	—	0.3

As of September 30, 2024 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is approximately 10 years.

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)

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. The Registrants have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. The total exposure of AEP's derivative contracts with collateral triggering events in a net liability position was immaterial as of September 30, 2024 and December 31, 2023. The Registrant Subsidiaries had no derivative contracts with collateral triggering events in a net liability position as of September 30, 2024 and December 31, 2023.

Cross-Acceleration Triggers (Applies to AEP & PSO)

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 $102 million and $107 million and no cash collateral posted as of September 30, 2024 and December 31, 2023, respectively. PSO had derivative contracts with cross-acceleration provisions in a net liability position of $11 million and $0 and no cash collateral posted as of September 30, 2024 and December 31, 2023, respectively. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required. The other Registrant Subsidiaries' derivative contracts with cross-acceleration provisions outstanding as of September 30, 2024 and December 31, 2023 were immaterial.

Cross-Default Triggers (Applies to AEP, APCo, 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 contracts with cross-default provisions in a net liability position of $174 million and $242 million and no cash collateral posted as of September 30, 2024 and December 31, 2023, respectively, after considering contractual netting arrangements. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $14 million, $11 million and $5 million, respectively, and no cash collateral posted as of September 30, 2024. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $22 million, $29 million and $15 million, respectively, and no cash collateral posted as of December 31, 2023. If a cross-default provision would have been triggered, settlement at fair value would have been required. The other Registrant Subsidiaries had no derivative contracts with cross-default provisions outstanding as of September 30, 2024 and December 31, 2023.

10. FAIR VALUE MEASUREMENTS

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

Fair Value Hierarchy and Valuation Techniques

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

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

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

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

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

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

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

	September 30, 2024		December 31, 2023	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in millions)			
AEP	$ 41,974.4	$ 40,104.2	$ 40,143.2	$ 37,325.7
AEP Texas	6,479.4	6,112.1	5,889.8	5,400.7
AEPTCo	5,862.3	5,288.5	5,414.4	4,796.9
APCo	5,659.2	5,582.5	5,588.3	5,390.1
I&M	3,517.5	3,363.4	3,499.4	3,291.6
OPCo	3,715.0	3,389.6	3,366.8	2,992.1
PSO	2,385.4	2,210.9	2,384.6	2,154.3
SWEPCo	3,648.7	3,329.1	3,646.9	3,209.7

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

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS.

The following is a summary of Other Temporary Investments and Restricted Cash:

	September 30, 2024			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash (a)	$ 53.4	$ —	$ —	$ 53.4
Other Cash Deposits	17.0	—	—	17.0
Fixed Income Securities – Mutual Funds (b)	168.0	—	(3.4)	164.6
Equity Securities – Mutual Funds	14.8	32.2	—	47.0
Total Other Temporary Investments and Restricted Cash	$ 253.2	$ 32.2	$ (3.4)	$ 282.0

	December 31, 2023			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash (a)	$ 48.9	$ —	$ —	$ 48.9
Other Cash Deposits	13.9	—	—	13.9
Fixed Income Securities – Mutual Funds (b)	165.9	—	(6.2)	159.7
Equity Securities – Mutual Funds	14.8	25.9	—	40.7
Total Other Temporary Investments and Restricted Cash	$ 243.5	$ 25.9	$ (6.2)	$ 263.2

(a) Primarily represents amounts held for the repayment of debt.
(b) Primarily short and intermediate maturities which may be sold and do not contain maturity dates.

The following table provides the activity for fixed income and equity securities within Other Temporary Investments:

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
	(in millions)			
Proceeds from Investment Sales	$ 4.5	$ 0.8	$ 7.5	$ 0.8
Purchases of Investments	6.0	14.6	9.0	16.9
Gross Realized Gains on Investment Sales	0.4	0.3	0.7	0.3
Gross Realized Losses on Investment Sales	0.3	—	0.5	—

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

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

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

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

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

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

The following is a summary of nuclear trust fund investments:

	September 30, 2024				December 31, 2023			
	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	$ 26.2	$ —	$ —	$ —	$ 16.8	$ —	$ —	$ —
Fixed Income Securities:								
United States Government	1,370.5	42.0	(0.1)	(22.5)	1,273.0	28.6	(3.9)	(33.2)
Corporate Debt	215.6	7.3	(1.8)	3.0	132.1	4.8	(5.2)	(8.6)
State and Local Government	1.7	—	—	—	1.7	—	—	—
Subtotal Fixed Income Securities	1,587.8	49.3	(1.9)	(19.5)	1,406.8	33.4	(9.1)	(41.8)
Equity Securities - Domestic	2,811.8	2,271.0	(0.3)	—	2,436.6	1,869.5	(0.9)	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 4,425.8	$ 2,320.3	$ (2.2)	$ (19.5)	$3,860.2	$ 1,902.9	$ (10.0)	$ (41.8)

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

	Three Months Ended September 30, 2024	Three Months Ended September 30, 2023	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023
	(in millions)			
Proceeds from Investment Sales	$ 1,181.9	$ 933.0	$ 2,336.0	$ 2,139.3
Purchases of Investments	1,201.9	949.5	2,389.0	2,182.8
Gross Realized Gains on Investment Sales	108.4	36.8	118.7	91.6
Gross Realized Losses on Investment Sales	0.7	7.7	6.1	20.0

The base cost of fixed income securities was $1.5 billion and $1.4 billion as of September 30, 2024 and December 31, 2023, respectively. The base cost of equity securities was $541 million and $568 million as of September 30, 2024 and December 31, 2023, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of September 30, 2024 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 401.2
After 1 year through 5 years	600.8
After 5 years through 10 years	249.7
After 10 years	336.1
Total	$ 1,587.8

__Fair Value Measurements of Financial Assets and Liabilities__

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

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 53.4	$ —	$ —	$ —	$ 53.4
Other Cash Deposits (a)	—	—	—	17.0	17.0
Fixed Income Securities – Mutual Funds	164.6	—	—	—	164.6
Equity Securities – Mutual Funds (b)	47.0	—	—	—	47.0
Total Other Temporary Investments and Restricted Cash	265.0	—	—	17.0	282.0
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	3.9	571.5	307.2	(484.1)	398.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	83.9	20.1	(7.5)	96.5
Interest Rate Hedges	—	—	—	—	—
Total Risk Management Assets	3.9	655.4	327.3	(491.6)	495.0
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	15.6	—	—	10.6	26.2
Fixed Income Securities:					
United States Government	—	1,370.5	—	—	1,370.5
Corporate Debt	—	215.6	—	—	215.6
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,587.8	—	—	1,587.8
Equity Securities – Domestic (b)	2,811.8	—	—	—	2,811.8
Total Spent Nuclear Fuel and Decommissioning Trusts	2,827.4	1,587.8	—	10.6	4,425.8
Total Assets	$ 3,096.3	$ 2,243.2	$ 327.3	$ (464.0)	$ 5,202.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 7.5	$ 574.8	$ 133.6	$ (456.5)	$ 259.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	8.5	0.6	(7.5)	1.6
Interest Rate Hedges	—	10.9	—	—	10.9
Fair Value Hedges	—	81.7	—	—	81.7
Total Risk Management Liabilities	$ 7.5	$ 675.9	$ 134.2	$ (464.0)	$ 353.6

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2023

Assets:	Level 1	Level 2	Level 3 (in millions)	Other	Total
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 48.9	$ —	$ —	$ —	$ 48.9
Other Cash Deposits (a)	—	—	—	13.9	13.9
Fixed Income Securities – Mutual Funds	159.7	—	—	—	159.7
Equity Securities – Mutual Funds (b)	40.7	—	—	—	40.7
Total Other Temporary Investments and Restricted Cash	249.3	—	—	13.9	263.2
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	9.7	736.9	274.3	(617.0)	403.9
Cash Flow Hedges:					
Commodity Hedges (c)	—	123.5	19.8	(8.5)	134.8
Total Risk Management Assets	9.7	860.4	294.1	(625.5)	538.7
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.8	—	—	9.0	16.8
Fixed Income Securities:					
United States Government	—	1,273.0	—	—	1,273.0
Corporate Debt	—	132.1	—	—	132.1
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,406.8	—	—	1,406.8
Equity Securities – Domestic (b)	2,436.6	—	—	—	2,436.6
Total Spent Nuclear Fuel and Decommissioning Trusts	2,444.4	1,406.8	—	9.0	3,860.2
Total Assets	$ 2,703.4	$ 2,267.2	$ 294.1	$ (602.6)	$ 4,662.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 24.7	$ 783.8	$ 154.1	$ (600.3)	$ 362.3
Cash Flow Hedges:					
Commodity Hedges (c)	—	9.6	0.6	(8.5)	1.7
Interest Rate Hedges	—	9.0	—	—	9.0
Fair Value Hedges	—	98.4	—	—	98.4
Total Risk Management Liabilities	$ 24.7	$ 900.8	$ 154.7	$ (608.8)	$ 471.4

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 45.1	$ —	$ —	$ —	$ 45.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ (0.6)	$ —	$ 0.6	$ —

December 31, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 34.0	$ —	$ —	$ —	$ 34.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.2	$ —	$ (0.2)	$ —
Cash Flow Hedges:					
Interest Rate Hedges	—	2.7	—	—	2.7
Total Risk Management Liabilities	$ —	$ 2.9	$ —	$ (0.2)	$ 2.7

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 8.3	$ —	$ —	$ —	$ 8.3
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	7.3	47.5	(7.7)	47.1
Total Assets	$ 8.3	$ 7.3	$ 47.5	$ (7.7)	$ 55.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 21.9	$ 0.3	$ (8.7)	$ 13.5

December 31, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 14.9	$ —	$ —	$ —	$ 14.9
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	1.1	23.5	(2.2)	22.4
Total Assets	$ 14.9	$ 1.1	$ 23.5	$ (2.2)	$ 37.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 24.0	$ 1.1	$ (2.6)	$ 22.5

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2024

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 12.7	$ 10.0	$ (1.0)	$ 21.7
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	15.6	—	—	10.6	26.2
Fixed Income Securities:					
United States Government	—	1,370.5	—	—	1,370.5
Corporate Debt	—	215.6	—	—	215.6
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,587.8	—	—	1,587.8
Equity Securities - Domestic (b)	2,811.8	—	—	—	2,811.8
Total Spent Nuclear Fuel and Decommissioning Trusts	2,827.4	1,587.8	—	10.6	4,425.8
Total Assets	$ 2,827.4	$ 1,600.5	$ 10.0	$ 9.6	$ 4,447.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.9	$ 0.7	$ (1.2)	$ 0.4

December 31, 2023

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 37.4	$ 4.5	$ (2.3)	$ 39.6
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.8	—	—	9.0	16.8
Fixed Income Securities:					
United States Government	—	1,273.0	—	—	1,273.0
Corporate Debt	—	132.1	—	—	132.1
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,406.8	—	—	1,406.8
Equity Securities - Domestic (b)	2,436.6	—	—	—	2,436.6
Total Spent Nuclear Fuel and Decommissioning Trusts	2,444.4	1,406.8	—	9.0	3,860.2
Total Assets	$ 2,444.4	$ 1,444.2	$ 4.5	$ 6.7	$ 3,899.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 3.7	$ 1.7	$ (3.4)	$ 2.0

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2024

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.4	$ 51.6	$ (0.4)	$ 51.6

December 31, 2023

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.2	$ 50.6	$ (0.1)	$ 50.7

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 0.6	$ 28.6	$ (0.7)	$ 28.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 12.2	$ 0.2	$ 10.0	$ 22.4
Cash Flow Hedges:					
Commodity Hedges (c)	—	—	—	(10.9)	(10.9)
Interest Rate Hedges	—	10.9	—	—	10.9
Total Risk Management Liabilities	$ —	$ 23.1	$ 0.2	$ (0.9)	$ 22.4

December 31, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 19.7	$ (0.7)	$ 19.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 29.6	$ 1.1	$ (0.8)	$ 29.9

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 0.3	$ 24.3	$ (0.5)	$ 24.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 5.0	$ 0.6	$ (0.8)	$ 4.8

December 31, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 0.5	$ 12.0	$ (0.9)	$ 11.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 15.7	$ 0.9	$ (1.0)	$ 15.6

(a) Amounts in "Other'' column primarily represent cash deposits in bank accounts with financial institutions or third-parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.
(b) Amounts represent publicly traded equity securities and equity-based mutual funds.
(c) Amounts in "Other'' column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging.''
(d) The September 30, 2024 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $(1) million in 2024 and $(2) million in periods 2025-2027; Level 2 matures $(23) million in 2024, $15 million in periods 2025-2027 and $5 million in periods 2028-2029; Level 3 matures $45 million in 2024, $129 million in periods 2025-2027, $17 million in periods 2028-2029 and $(18) million in periods 2030-2032. Risk management commodity contracts are substantially comprised of power contracts.
(e) Amounts in "Other'' column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.
(f) The December 31, 2023 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $(11) million in 2024 and $(4) million in 2025-2027; Level 2 matures $(99) million in 2024, $(44) million in periods 2025-2027, $7 million in periods 2028-2029 and $2 million in periods 2030-2033; Level 3 matures $74 million in 2024, $43 million in periods 2025-2027, $18 million in periods 2028-2029 and $(16) million in periods 2030-2033. Risk management commodity contracts are substantially comprised of power contracts.

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

Three Months Ended September 30, 2024	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of June 30, 2024	$ 288.2	$ 67.8	$ 14.5	$ (43.2)	$ 49.4	$ 38.1
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	60.4	13.4	2.9	(0.1)	23.2	21.2
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(6.9)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(0.1)	—	—	—	—	—
Settlements	(133.1)	(26.9)	(7.9)	1.0	(46.3)	(37.7)
Transfers into Level 3 (d) (e)	(0.3)	—	—	—	—	—
Transfers out of Level 3 (e)	(0.6)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(14.5)	(7.1)	(0.2)	(9.3)	2.1	2.1
Balance as of September 30, 2024	$ 193.1	$ 47.2	$ 9.3	$ (51.6)	$ 28.4	$ 23.7

Three Months Ended September 30, 2023	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of June 30, 2023	$ 126.1	$ 39.4	$ 6.8	$ (54.0)	$ 43.1	$ 26.0
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	39.7	10.0	2.3	—	14.2	14.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	72.7	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	4.9	—	—	—	—	—
Settlements	(87.1)	(16.5)	(3.7)	1.1	(30.5)	(24.8)
Transfers out of Level 3 (e)	6.6	0.1	(0.1)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	19.9	12.1	1.3	1.3	0.4	1.3
Balance as of September 30, 2023	$ 182.8	$ 45.1	$ 6.6	$ (51.6)	$ 27.2	$ 16.5

Nine Months Ended September 30, 2024	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2023	$ 139.4	$ 22.4	$ 2.8	$ (50.6)	$ 18.6	$ 11.1
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	90.6	24.1	7.3	(0.9)	26.2	23.6
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	2.3	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	1.5	—	—	—	—	—
Settlements	(164.7)	(46.5)	(10.0)	6.0	(44.8)	(36.0)
Transfers into Level 3 (d) (e)	6.8	—	—	—	—	—
Transfers out of Level 3 (e)	2.2	—	—	—	—	0.5
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	115.0	47.2	9.2	(6.1)	28.4	24.5
Balance as of September 30, 2024	$ 193.1	$ 47.2	$ 9.3	$ (51.6)	$ 28.4	$ 23.7

Nine Months Ended September 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)	(41.3)	(47.0)	(1.7)	(2.4)	3.5	5.9
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	67.7	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(10.5)	—	—	—	—	—
Settlements	(85.9)	(22.1)	(2.9)	3.5	(27.2)	(20.0)
Transfers into Level 3 (d) (e)	(6.1)	—	—	—	—	—
Transfers out of Level 3 (e)	3.8	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	94.7	45.1	6.6	(12.7)	27.2	16.4
Balance as of September 30, 2023	$ 182.8	$ 45.1	$ 6.6	$ (51.6)	$ 27.2	$ 16.5

(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
September 30, 2024

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Input/Range Weighted Average (a)
		(in millions)						
AEP	Energy Contracts	$ 199.9	$ 130.4	Discounted Cash Flow	Forward Market Price (b)	$ 0.46	$ 121.80	$ 45.50
AEP	FTRs	127.4	3.8	Discounted Cash Flow	Forward Market Price (b)	(41.91)	24.96	0.20
APCo	FTRs	47.5	0.3	Discounted Cash Flow	Forward Market Price (b)	(0.06)	9.63	1.30
I&M	FTRs	10.0	0.7	Discounted Cash Flow	Forward Market Price (b)	(5.00)	9.63	1.21
OPCo	Energy Contracts	—	51.6	Discounted Cash Flow	Forward Market Price (b)	19.94	68.22	41.34
PSO	FTRs	28.6	0.2	Discounted Cash Flow	Forward Market Price (b)	(41.91)	5.93	(3.82)
SWEPCo	FTRs	24.3	0.6	Discounted Cash Flow	Forward Market Price (b)	(41.91)	5.93	(3.82)

December 31, 2023

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Input/Range Weighted Average (a)
		(in millions)						
AEP	Energy Contracts	$ 225.5	$ 144.9	Discounted Cash Flow	Forward Market Price (b)	$ 5.21	$ 153.77	$ 45.05
AEP	Natural Gas Contracts	—	0.5	Discounted Cash Flow	Forward Market Price (c)	3.11	3.11	3.11
AEP	FTRs	68.6	9.3	Discounted Cash Flow	Forward Market Price (b)	(25.45)	17.07	—
APCo	FTRs	23.5	1.1	Discounted Cash Flow	Forward Market Price (b)	(1.04)	6.45	1.36
I&M	FTRs	4.5	1.7	Discounted Cash Flow	Forward Market Price (b)	(1.48)	8.40	0.85
OPCo	Energy Contracts	—	50.6	Discounted Cash Flow	Forward Market Price (b)	22.92	67.53	42.85
PSO	FTRs	19.7	1.1	Discounted Cash Flow	Forward Market Price (b)	(25.45)	4.80	(4.33)
SWEPCo	Natural Gas Contracts	—	0.5	Discounted Cash Flow	Forward Market Price (c)	3.11	3.11	3.11
SWEPCo	FTRs	12.0	0.4	Discounted Cash Flow	Forward Market Price (b)	(25.45)	4.80	(4.33)

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

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 September 30, 2024 and December 31, 2023:

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 2024 and 2023, adjusted for tax expense associated with certain discrete items. In the first quarter of 2024, I&M, PSO, and SWEPCo recorded tax benefits of $61 million, $49 million and $114 million, respectively, related to the reduction of a regulatory liability associated with the PLRs received from the IRS. In the third quarter of 2024, I&M recorded a $61 million tax benefit related to Nuclear PTCs. The actual Nuclear PTC realized by AEP and I&M in 2024 could vary significantly based on annual generation, and/or the U.S. Treasury guidance, particularly computational guidance on gross receipts. These items are the primary drivers of the interim ETR resulting in AEP's year to date tax rate of (4.4)% as shown below.

The ETR for each of the Registrants are included in the following tables:

	Three Months Ended September 30, 2024							
	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 and Local Income Taxes, Net	0.6 %	0.3 %	2.5 %	1.4 %	0.7 %	1.1 %	— %	(2.6)%
Tax Reform Excess ADIT Reversal	(2.8)%	(1.0)%	0.2 %	(2.3)%	(7.9)%	(7.3)%	(5.0)%	(3.2)%
Production and Investment Tax Credits	(9.9)%	— %	— %	(0.1)%	(45.6)%	— %	(61.9)%	(23.4)%
Reversal of Origination Flow-Through	0.1 %	0.1 %	0.3 %	(1.1)%	0.3 %	0.7 %	0.3 %	0.6 %
AFUDC Equity	(1.5)%	(2.3)%	(1.9)%	(1.5)%	(1.2)%	(1.2)%	(1.3)%	(0.5)%
Discrete Tax Adjustments	(3.7)%	— %	— %	— %	— %	— %	— %	— %
Other	— %	0.2 %	(0.2)%	(0.4)%	— %	0.6 %	1.5 %	— %
Effective Income Tax Rate	3.8 %	18.3 %	21.9 %	17.0 %	(32.7)%	14.9 %	(45.4)%	(8.1)%

	Three Months Ended September 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 and Local Income Taxes, Net	1.4 %	0.5 %	2.8 %	2.2 %	2.1 %	0.8 %	3.0 %	(4.3)%
Tax Reform Excess ADIT Reversal	(5.7)%	(1.3)%	(0.2)%	(5.3)%	(8.5)%	(6.8)%	(17.0)%	(6.2)%
Production and Investment Tax Credits	(5.1)%	0.1 %	— %	(0.1)%	(0.7)%	— %	(46.9)%	(25.5)%
Reversal of Origination Flow-Through	0.1 %	0.2 %	0.3 %	1.8 %	0.7 %	0.8 %	0.3 %	(0.2)%
AFUDC Equity	(1.4)%	(1.4)%	(2.4)%	(1.5)%	(0.5)%	(0.8)%	(1.6)%	(0.8)%
Discrete Tax Adjustments	(4.1)%	— %	— %	— %	— %	— %	— %	— %
Other	0.1 %	(0.5)%	(1.0)%	0.7 %	(3.5)%	1.3 %	(0.2)%	0.2 %
Effective Income Tax Rate	6.3 %	18.6 %	20.5 %	18.8 %	10.6 %	16.3 %	(41.4)%	(15.8)%

	Nine Months Ended September 30, 2024							
	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 and Local Income Taxes, Net	1.2 %	0.4 %	2.5 %	2.1 %	1.5 %	0.9 %	— %	(2.6)%
Tax Reform Excess ADIT Reversal	(3.1)%	(1.1)%	0.2 %	(7.1)%	(5.7)%	(8.7)%	(4.3)%	(4.2)%
Remeasurement of Excess ADIT	(11.9)%	1.5 %	— %	— %	(27.5)%	— %	(40.5)%	(181.8)%
Production and Investment Tax Credits	(8.3)%	(0.1)%	— %	(0.1)%	(23.4)%	— %	(61.7)%	(79.1)%
Reversal of Origination Flow-Through	0.2 %	0.1 %	0.3 %	(0.8)%	0.3 %	0.8 %	0.3 %	2.1 %
AFUDC Equity	(1.6)%	(1.7)%	(2.0)%	(1.1)%	(1.1)%	(1.3)%	(1.3)%	(2.3)%
Discrete Tax Adjustments	(2.1)%	— %	— %	— %	— %	— %	1.2 %	1.1 %
Other	0.2 %	— %	(0.1)%	(0.1)%	— %	0.4 %	— %	(0.5)%
Effective Income Tax Rate	(4.4)%	20.1 %	21.9 %	13.9 %	(34.9)%	13.1 %	(85.3)%	(246.3)%

	Nine Months Ended September 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 and Local Income Taxes, Net	1.7 %	0.5 %	2.7 %	2.4 %	2.3 %	0.9 %	2.8 %	(2.9)%
Tax Reform Excess ADIT Reversal	(6.0)%	(1.3)%	0.1 %	(4.8)%	(7.6)%	(7.3)%	(17.1)%	(5.3)%
Production and Investment Tax Credits	(7.4)%	— %	— %	(0.1)%	(0.6)%	— %	(48.9)%	(26.7)%
Reversal of Origination Flow-Through	(0.2)%	0.2 %	0.3 %	0.1 %	(1.7)%	0.8 %	0.3 %	(0.3)%
AFUDC Equity	(1.4)%	(1.2)%	(2.0)%	(1.2)%	(0.4)%	(0.8)%	(1.5)%	(0.5)%
Discrete Tax Adjustments	(2.8)%	— %	— %	1.5 %	0.7 %	— %	— %	— %
Other	0.3 %	(0.2)%	(0.5)%	0.4 %	(1.2)%	0.5 %	(0.2)%	0.2 %
Effective Income Tax Rate	5.2 %	19.0 %	21.6 %	19.3 %	12.5 %	15.1 %	(43.6)%	(14.5)%

Federal and State Income Tax Audit Status

The statute of limitations ("SOL") for the IRS to examine AEP and subsidiaries originally filed federal return has expired for tax years 2016 and earlier. In July 2024, the Congressional Joint Committee on Taxation ("JCT") completed its review of the results of the 2017-2020 IRS Audit and agreed to them. AEP received the associated tax refund and interest payment in September 2024.

This IRS audit and associated refund claim resulted from a net operating loss carryback to 2015 that originated in the 2017 return. AEP agreed to extend the SOL on the 2017-2020 tax returns to May 31, 2025, to allow the JCT adequate time to complete its review. However, AEP has IRS confirmation that tax years 2017-2020 are now effectively closed as they only remain open for changes to other non-consolidated entities that AEP holds an interest in.

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 SOL 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 created a 15% minimum tax on adjusted financial statement income (CAMT), extended and increased the value of PTCs and ITCs, added a nuclear and clean hydrogen PTC, an energy storage ITC and allowed 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 September 2024, Treasury and the IRS issued proposed regulations on the application of CAMT. AEP and subsidiaries are subject to the CAMT and are expected to incur a liability in 2024. However, any CAMT cash taxes incurred 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 are presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. AEP presents the loss on sale of tax credits through income tax expense.

In April 2024, the IRS issued final regulations related to the transfer of tax credits. In 2023, AEP, on behalf of PSO, SWEPCo and AEP Energy Supply LLC, entered into transferability agreements with nonaffiliated parties to sell 2023 generated PTCs resulting in cash proceeds of approximately $174 million with $102 million received in 2023, $62 million received in the first quarter of 2024 and the remaining $10 million was received in the second quarter of 2024. In the third quarter of 2024, AEP, on behalf of PSO, SWEPCo and APCo, entered into transferability agreements with nonaffiliated parties to sell 2024 generated PTCs which will result in approximately $137 million of cash proceeds, of which approximately $91 million was received in the third quarter of 2024 and the remaining $46 million is expected to be received in the fourth quarter of 2024 and the first quarter of 2025. AEP expects to continue to explore the ability to efficiently monetize its tax credits through third-party transferability agreements.

I&M's Cook Plant qualifies for the transferable Nuclear PTC, which is available for tax years beginning in 2024 through 2032. The Nuclear PTC is calculated based on electricity generated and sold to third-parties and is subject to a "reduction amount" as the facility's gross receipts increase above a certain threshold. In the third quarter of 2024, AEP and I&M have included $64 million of estimated Nuclear PTCs within their annualized ETR. Absent specific IRS guidance, AEP and I&M's estimated 2024 Nuclear PTC was calculated using estimated 2024 gross receipts and forecasted annual generation for the Cook Plant. If, and when, IRS guidance is eventually issued, the value of the estimated Nuclear PTC will be updated to reflect such guidance, if necessary.

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 2023, 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 $1.7 billion of its common stock through an ATM 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. For the nine months ended September 30, 2024, AEP issued 4,437,136 shares of common stock and received net cash proceeds of $397 million under the ATM program. As of September 30, 2024, approximately $1.3 billion of equity is available for issuance under the ATM program.

Long-term Debt Outstanding (Applies to AEP)

The following table details long-term debt outstanding, net of issuance costs and premiums or discounts:

Type of Debt	September 30, 2024	December 31, 2023
	(in millions)	
Senior Unsecured Notes	$ 35,771.2	$ 33,779.4
Pollution Control Bonds	1,770.4	1,771.6
Notes Payable	644.3	193.3
Securitization Bonds	285.7	368.9
Spent Nuclear Fuel Obligation (a)	312.7	300.4
Junior Subordinated Notes	2,578.0	2,388.1
Other Long-term Debt	612.1	1,341.5
Total Long-term Debt Outstanding	41,974.4	40,143.2
Long-term Debt Due Within One Year	2,826.7	2,490.5
Long-term Debt	$ 39,147.7	$ 37,652.7

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for SNF disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $366 million and $348 million as of September 30, 2024 and December 31, 2023, respectively, and are included in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

Long-term Debt Activity

Long-term debt and other securities issued, retired and principal payments made during the first nine months of 2024 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		**(in millions)**	**(%)**	
AEP	Junior Subordinated Notes	$ 600.0	6.95	2054
AEP	Junior Subordinated Notes	400.0	7.05	2054
AEPTCo	Senior Unsecured Notes	450.0	5.15	2034
AEP Texas	Senior Unsecured Notes	500.0	5.45	2029
AEP Texas	Senior Unsecured Notes	350.0	5.70	2034
APCo	Pollution Control Bonds	86.0	3.38	2028
APCo	Senior Unsecured Notes	400.0	5.65	2034
I&M	Notes Payable	80.4	6.41	2028
OPCo	Senior Unsecured Notes	350.0	5.65	2034
Non-Registrant:				
AEGCo	Other Long-term Debt	70.0	Variable	2025
Transource Energy	Other Long-term Debt	50.0	Variable	2025
WPCo	Notes Payable	450.0	6.89	2034
Total Issuances		$ 3,786.4		

(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	Junior Subordinated Debt	$ 805.0	2.03	2024
AEP Texas	Other Long-term Debt	200.0	Variable	2025
AEP Texas	Securitization Bonds	32.6	2.85	2024
AEP Texas	Securitization Bonds	23.9	2.06	2025
APCo	Other Long-term Debt	300.0	Variable	2024
APCo	Other Long-term Debt	0.1	13.72	2026
APCo	Pollution Control Bonds	86.0	2.55	2024
APCo	Securitization Bonds	27.4	3.77	2028
I&M	Notes Payable	1.7	Variable	2024
I&M	Notes Payable	7.4	0.93	2025
I&M	Notes Payable	2.9	Variable	2025
I&M	Notes Payable	15.2	3.44	2026
I&M	Notes Payable	15.1	5.93	2027
I&M	Notes Payable	20.6	6.01	2028
I&M	Notes Payable	11.4	6.41	2028
I&M	Other Long-term Debt	1.8	6.00	2025
PSO	Other Long-term Debt	0.4	3.00	2027
Non-Registrant:				
AEGCo	Notes Payable	5.0	2.43	2028
AEGCo	Other Long-term Debt	80.0	Variable	2024
KPCo	Senior Unsecured Notes	65.0	3.13	2024
Transource Energy	Senior Unsecured Notes	1.4	2.75	2050
Transource Energy	Senior Unsecured Notes	1.2	2.75	2050
WPCo	Notes Payable	265.0	Variable	2024
Total Retirements and Principal Payments		$ 1,969.1		

Long-term Debt Subsequent Events

In October 2024, I&M retired $9 million of Notes Payable related to DCC Fuel.

In October 2024, Transource Energy issued $2 million of variable rate Other Long-term Debt due in 2025.

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 0.3% of consolidated tangible net assets as of September 30, 2024. 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 (Applies to all Registrant Subsidiaries)

AEP subsidiaries use a corporate borrowing program to meet their short-term borrowing needs. 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 Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of September 30, 2024 and December 31, 2023 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized borrowing limits for the nine months ended September 30, 2024 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of September 30, 2024	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 374.6	$ 274.3	$ 237.0	$ 203.1	$ 54.7	$ 600.0	
AEPTCo	313.3	332.0	75.7	159.2	152.6	820.0	(a)
APCo	399.5	132.3	110.2	32.6	18.0	750.0	
I&M	126.9	8.4	53.3	3.9	(77.0)	500.0	
OPCo	310.0	159.9	180.5	75.9	97.4	600.0	
PSO	302.2	—	184.0	—	(98.5)	750.0	
SWEPCo	362.2	—	243.2	—	(237.4)	750.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above table does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of September 30, 2024 and December 31, 2023 are included in Advances to Affiliates on the subsidiaries' balance sheets. The Nonutility Money Pool participants' activity for the nine months ended September 30, 2024 is described in the following table:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of September 30, 2024
		(in millions)	
AEP Texas	$ 7.1	$ 7.0	$ 7.1
SWEPCo	2.8	2.6	2.8

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of borrowings from AEP as of September 30, 2024 and December 31, 2023 are included in Advances from Affiliates on AEPTCo's balance sheets. AEPTCo's direct financing activities with AEP and corresponding authorized borrowing limit for the nine months ended September 30, 2024 are described in the following table:

Company	Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of September 30,	Loans to AEP as of September 30,	Authorized Short-term Borrowing Limit (a)
				(in millions)			
AEPTCo Parent	$ 49.4	$ 148.5	$ 15.3	$ 69.8	$ 11.8	$ —	$ —
AEP SWTCo	$ 1.9	$ —	$ 1.8	$ —	$ 1.8	$ —	$ 50.0

(a) Amount represents the authorized short-term borrowing limit from FERC or state regulatory agencies not otherwise included in the utility money pool above.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Nine Months Ended September 30, 2024	2023
Maximum Interest Rate	5.79 %	5.81 %
Minimum Interest Rate	5.14 %	4.66 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized in the following table:

Company	Average Interest Rate for Funds Borrowed from the Utility Money Pool for Nine Months Ended September 30, 2024	2023	Average Interest Rate for Funds Loaned to the Utility Money Pool for Nine Months Ended September 30, 2024	2023
AEP Texas	5.69 %	5.44 %	5.48 %	5.70 %
AEPTCo	5.68 %	5.29 %	5.58 %	5.52 %
APCo	5.72 %	5.47 %	5.51 %	5.47 %
I&M	5.64 %	5.13 %	5.44 %	5.54 %
OPCo	5.70 %	5.37 %	5.49 %	5.60 %
PSO	5.59 %	5.48 %	— %	5.24 %
SWEPCo	5.58 %	5.25 %	— %	5.72 %

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

	Nine Months Ended September 30, 2024			Nine Months Ended September 30, 2023		
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	5.79 %	5.25 %	5.64 %	5.81 %	4.66 %	5.47 %
SWEPCo	5.79 %	5.25 %	5.64 %	5.81 %	4.66 %	5.49 %

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

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
2024	5.79 %	5.25 %	5.79 %	5.25 %	5.66 %	5.63 %
2023	5.81 %	4.53 %	5.81 %	4.53 %	5.43 %	5.46 %

Short-term Debt (Applies to AEP and SWEPCo)

Outstanding short-term debt was as follows:

		September 30, 2024		December 31, 2023	
Company	Type of Debt	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
		(dollars in millions)			
AEP	Securitized Debt for Receivables (b)	$ 900.0	5.32 %	$ 888.0	5.65 %
AEP	Commercial Paper	755.0	5.26 %	1,937.9	5.69 %
SWEPCo	Notes Payable	4.6	7.20 %	4.3	7.71 %
	Total Short-term Debt	$ 1,659.6		$ 2,830.2	

(a) Weighted-average rate as of September 30, 2024 and December 31, 2023, 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 $900 million from bank conduits to purchase receivables and expires in September 2026. As of September 30, 2024, 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 September 30,		Nine Months Ended September 30,	
	2024	2023	2024	2023
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	5.50 %	5.55 %	5.54 %	5.23 %
Net Uncollectible Accounts Receivable Written-Off	$ 8.4	$ 8.8	$ 22.3	$ 22.9

	September 30, 2024	December 31, 2023
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,285.4	$ 1,207.4
Short-term – Securitized Debt of Receivables	900.0	888.0
Delinquent Securitized Accounts Receivable	66.4	52.2
Bad Debt Reserves Related to Securitization	44.9	42.0
Unbilled Receivables Related to Securitization	327.4	409.8

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. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreements were:

Company	September 30, 2024	December 31, 2023
	(in millions)	
APCo	$ 178.5	$ 184.6
I&M	183.6	156.4
OPCo	517.2	541.7
PSO	192.2	134.6
SWEPCo	189.2	168.3

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2024	2023	2024	2023
		(in millions)		
APCo	$ 4.0	$ 4.1	$ 12.1	$ 13.3
I&M	4.1	4.4	12.0	12.2
OPCo	7.5	7.4	22.3	22.3
PSO	4.1	4.6	10.9	11.3
SWEPCo	4.4	5.2	13.5	13.9

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Company	2024	2023	2024	2023
		(in millions)		
APCo	$ 504.6	$ 451.6	$ 1,487.9	$ 1,372.7
I&M	576.7	553.3	1,608.5	1,575.9
OPCo	860.0	850.3	2,477.2	2,518.6
PSO	611.5	633.8	1,398.1	1,510.3
SWEPCo	531.4	558.4	1,428.7	1,456.5

13. VOLUNTARY SEVERANCE PROGRAM

In April 2024, management announced a voluntary severance program designed to achieve a reduction in the size of AEP's workforce. Approximately 7,400 of AEP's 16,800 employees were eligible to participate in the program. Approximately 1,000 employees chose to take the voluntary severance package and substantially all terminated employment in July 2024. The severance program provides two weeks of base pay for every year of service with a minimum of four weeks and a maximum of 52 weeks of base pay. Certain positions impacted by the voluntary severance program have been and will continue to be refilled to maintain safe, effective and efficient operations. Net savings from the program will help offset increasing operating expenses and high interest costs in order to keep electricity costs affordable for customers.

AEP recorded a charge to expense in the second quarter of 2024 related to this voluntary severance program.

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Severance Expense Incurred	$ 122.0	$ 19.8	$ 10.7	$ 26.5	$ 14.8	$ 14.8	$ 10.1	$ 16.9
Settled/Adjustments	111.0	19.5	10.7	24.7	14.3	14.4	9.8	15.9
Remaining Balance as of September 30, 2024	$ 11.0	$ 0.3	$ —	$ 1.8	$ 0.5	$ 0.4	$ 0.3	$ 1.0

These expenses were primarily included in Other Operation and Maintenance on the statements of income and Other Current Liabilities on the balance sheets. The voluntary severance program has not triggered any material curtailment or settlement accounting considerations under the accounting guidance for "Compensation - Retirement Benefits".

AEP continues to monitor settlements under the qualified pension plan and will assess if the threshold of $306 million is reached in the fourth quarter of 2024. In the event the settlement threshold is reached during 2024, settlement accounting would result in a plan remeasurement and approximately $75 million to $100 million of the net actuarial loss to be recognized in AEP's Statement of Income. If the settlement threshold is reached, AEP expects to seek recovery for the portion of the loss related to regulated operations.

14. 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. Management believes that significant assumptions and judgments were applied consistently.

AEP holds ownership interests in businesses with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE, and if so, whether or not the VIE should be consolidated into AEP's financial statements. AEP has not provided material financial or other support that was not previously contractually required to any of its consolidated VIEs. If an entity is determined not to be a VIE, or if the entity is determined to be a VIE and AEP is not deemed to be the primary beneficiary, the entity is accounted for under the equity method of accounting.

Consolidated Variable Interest Entities

The Annual Report on Form 10-K for the year ended December 31, 2023 includes a detailed discussion of the Registrants' consolidated VIEs.

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

September 30, 2024

	Consolidated VIEs							
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding	AEP Credit	Protected Cell of EIS	Transource Energy
	(in millions)							
ASSETS								
Current Assets	$ 6.6	$ 93.6	$ 44.5	$ 15.9	$ 5.6	$ 1,287.0	$ 232.1	$ 35.0
Net Property, Plant and Equipment	—	160.5	—	—	—	—	—	581.0
Other Noncurrent Assets	120.1	76.0	19.6 (a)	127.8 (b)	117.0 (c)	11.0	—	4.1
Total Assets	$ 126.7	$ 330.1	$ 64.1	$ 143.7	$ 122.6	$ 1,298.0	$ 232.1	$ 620.1
LIABILITIES AND EQUITY								
Current Liabilities	$ 23.9	$ 93.4	$ 43.2	$ 29.9	$ 29.4	$ 1,230.9	$ 58.8	$ 26.4
Noncurrent Liabilities	102.5	236.7	16.3	112.5	91.3	1.0	106.5	289.4
Equity	0.3	—	4.6	1.3	1.9	66.1	66.8	304.3
Total Liabilities and Equity	$ 126.7	$ 330.1	$ 64.1	$ 143.7	$ 122.6	$ 1,298.0	$ 232.1	$ 620.1

(a) Includes an intercompany item eliminated in consolidation of $2 million.
(b) Includes an intercompany item eliminated in consolidation of $5 million.
(c) Includes an intercompany item eliminated in consolidation of $1 million.

December 31, 2023

	Consolidated VIEs							
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding	AEP Credit	Protected Cell of EIS	Transource Energy
	(in millions)							
ASSETS								
Current Assets	$ 4.2	$ 81.9	$ 25.5	$ 27.5	$ 13.3	$ 1,208.8	$ 205.3	$ 36.9
Net Property, Plant and Equipment	—	153.8	—	—	—	—	—	533.4
Other Noncurrent Assets	150.7	81.7	71.4 (a)	145.6 (b)	138.2 (c)	9.6	—	5.1
Total Assets	$ 154.9	$ 317.4	$ 96.9	$ 173.1	$ 151.5	$ 1,218.4	$ 205.3	$ 575.4
LIABILITIES AND EQUITY								
Current Liabilities	$ 19.9	$ 81.7	$ 75.5	$ 36.8	$ 29.9	$ 1,155.0	$ 49.2	$ 45.3
Noncurrent Liabilities	134.8	235.7	17.0	135.1	119.7	0.9	91.7	241.5
Equity	0.2	—	4.4	1.2	1.9	62.5	64.4	288.6
Total Liabilities and Equity	$ 154.9	$ 317.4	$ 96.9	$ 173.1	$ 151.5	$ 1,218.4	$ 205.3	$ 575.4

(a) Includes an intercompany item eliminated in consolidation of $8 million.
(b) Includes an intercompany item eliminated in consolidation of $6 million.
(c) Includes an intercompany item eliminated in consolidation of $2 million.

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, 2023 includes a detailed discussion of significant variable interests in non-consolidated VIEs and other significant equity method investments.

15. PROPERTY, PLANT AND EQUIPMENT

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

Asset Retirement Obligations

The Registrants record ARO in accordance with the accounting guidance for “Asset Retirement and Environmental Obligations” for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms, solar farms and certain coal mining facilities. The table below summarizes significant changes to the Registrants ARO recorded in 2024 and should be read in conjunction with the Property, Plant and Equipment note within the 2023 Annual Report.

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land. In the second quarter of 2024, AEP evaluated the applicability of the rule to current and former plant sites and incurred ARO liabilities of $602 million and revised cash flow estimates by an additional $72 million based on initial cost estimates. See the “Federal EPA’s Revised CCR Rule” section of Note 5 for additional information.

The following is a reconciliation of the aggregate carrying amounts of ARO by registrant:

Company	ARO as of December 31, 2023	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of September 30, 2024
			(in millions)			
AEP(b)(c)(d)(e)(f)(g)	$ 3,031.2	$ 97.2	$ 606.0	$ (80.3)	$ 122.9	$ 3,777.0
AEP Texas (b)(e)	4.5	0.2	—	(0.8)	—	3.9
APCo (b)(e)	464.0	17.6	247.1	(14.2)	97.2	811.7
I&M (b)(c)(e)	2,106.0	59.1	85.7	(1.9)	—	2,248.9
OPCo (b)(e)	2.1	0.6	52.9	(0.1)	—	55.5
PSO (b)(e)(g)	84.2	4.1	33.7	(1.1)	—	120.9
SWEPCo (b)(d)(e)(g)	281.6	10.8	23.8	(54.2)	19.9	281.9

(a) Unless discussed above, primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $2.1 billion and $2.1 billion as of September 30, 2024 and December 31, 2023, respectively.
(d) Includes ARO related to Sabine and DHLC.
(e) Includes ARO related to asbestos removal.
(f) Includes ARO related to solar farms.
(g) Includes ARO related to wind farms.

16. 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 and Registrant Subsidiary revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Three Months Ended September 30, 2024						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,362.9	$ 773.7	$ —	$ —	$ —	$ —	$ 2,136.6
Commercial Revenues	776.1	396.5	—	—	—	—	1,172.6
Industrial Revenues (a)	692.6	123.7	—	—	—	(0.3)	816.0
Other Retail Revenues	63.8	13.9	—	—	—	—	77.7
Total Retail Revenues	2,895.4	1,307.8	—	—	—	(0.3)	4,202.9
Wholesale and Competitive Retail Revenues:							
Generation Revenues	202.5	—	—	25.4	—	0.1	228.0
Transmission Revenues (b)	129.6	195.1	505.5	—	—	(439.4)	390.8
Renewable Generation Revenues (a)	—	—	—	8.7	—	(1.5)	7.2
Retail, Trading and Marketing Revenues (c)	—	—	—	529.3	(0.2)	(13.8)	515.3
Total Wholesale and Competitive Retail Revenues	332.1	195.1	505.5	563.4	(0.2)	(454.6)	1,141.3
Other Revenues from Contracts with Customers (d)	76.2	58.9	5.8	0.8	37.6	(53.4)	125.9
Total Revenues from Contracts with Customers	3,303.7	1,561.8	511.3	564.2	37.4	(508.3)	5,470.1
Other Revenues:							
Alternative Revenue Programs (a) (e)	0.3	10.3	1.2	—	—	1.0	12.8
Other Revenues (a) (f)	(1.0)	3.3	—	(65.1)	0.7	(0.7)	(62.8)
Total Other Revenues	(0.7)	13.6	1.2	(65.1)	0.7	0.3	(50.0)
Total Revenues	$ 3,303.0	$ 1,575.4	$ 512.5	$ 499.1	$ 38.1	$ (508.0)	$ 5,420.1

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $402 million. The affiliated revenue for Vertically Integrated Utilities was $51 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $14 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $34 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.

	Three Months Ended September 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	$ 1,326.7	$ 772.5	$ —	$ —	$ —	$ —	$ 2,099.2
Commercial Revenues	753.3	387.7	—	—	—	—	1,141.0
Industrial Revenues	699.9	138.9	—	—	—	(0.3)	838.5
Other Retail Revenues	66.6	13.0	—	—	—	—	79.6
Total Retail Revenues	2,846.5	1,312.1	—	—	—	(0.3)	4,158.3
Wholesale and Competitive Retail Revenues:							
Generation Revenues	174.3	—	—	31.8	—	(0.3)	205.8
Transmission Revenues (a)	120.6	176.0	466.1	—	—	(425.1)	337.6
Renewable Generation Revenues (b)	—	—	—	19.8	—	(2.5)	17.3
Retail, Trading and Marketing Revenues (c)	—	—	—	510.8	0.8	(36.7)	474.9
Total Wholesale and Competitive Retail Revenues	294.9	176.0	466.1	562.4	0.8	(464.6)	1,035.6
Other Revenues from Contracts with Customers (d)	61.3	58.2	4.8	0.9	55.6	(48.5)	132.3
Total Revenues from Contracts with Customers	3,202.7	1,546.3	470.9	563.3	56.4	(513.4)	5,326.2
Other Revenues:							
Alternative Revenue Programs (b) (e)	0.5	(5.0)	5.8	—	—	5.7	7.0
Other Revenues (b) (f)	2.2	2.8	—	3.4	0.8	(0.7)	8.5
Total Other Revenues	2.7	(2.2)	5.8	3.4	0.8	5.0	15.5
Total Revenues	$ 3,205.4	$ 1,544.1	$ 476.7	$ 566.7	$ 57.2	$ (508.4)	$ 5,341.7

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $366 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 $37 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $32 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.

	Three Months Ended September 30, 2024						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 230.2	$ —	$ 442.6	$ 249.4	$ 543.4	$ 301.1	$ 260.1
Commercial Revenues	120.3	—	196.4	169.9	276.2	165.1	172.5
Industrial Revenues (a)	33.7	—	201.2	155.4	89.9	98.5	102.5
Other Retail Revenues	9.7	—	28.1	1.2	4.2	30.8	2.3
Total Retail Revenues	393.9	—	868.3	575.9	913.7	595.5	537.4
Wholesale Revenues:							
Generation Revenues (b)	—	—	78.7	113.5	—	2.1	42.7
Transmission Revenues (c)	170.6	491.9	45.6	10.4	24.5	12.0	50.0
Total Wholesale Revenues	170.6	491.9	124.3	123.9	24.5	14.1	92.7
Other Revenues from Contracts with Customers (d)	8.2	6.0	36.2	35.3	50.8	6.0	8.8
Total Revenues from Contracts with Customers	572.7	497.9	1,028.8	735.1	989.0	615.6	638.9
Other Revenues:							
Alternative Revenue Programs (a) (e)	(1.5)	(0.7)	—	(0.4)	11.9	(0.2)	(0.1)
Other Revenues (a)	—	—	0.1	(1.2)	3.3	—	—
Total Other Revenues	(1.5)	(0.7)	0.1	(1.6)	15.2	(0.2)	(0.1)
Total Revenues	$ 571.2	$ 497.2	$ 1,028.9	$ 733.5	$ 1,004.2	$ 615.4	$ 638.8

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $41 million primarily related to the PPA with KGPCo.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $399 million, APCo was $22 million and SWEPCo was $22 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $18 million primarily related 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.

	Three Months Ended September 30, 2023						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 236.2	$ —	$ 397.1	$ 230.7	$ 536.3	$ 310.5	$ 286.5
Commercial Revenues	112.4	—	181.3	159.2	275.3	171.9	174.9
Industrial Revenues	35.4	—	197.1	159.1	103.6	114.1	105.5
Other Retail Revenues	9.2	—	26.8	1.3	3.8	33.8	2.4
Total Retail Revenues	393.2	—	802.3	550.3	919.0	630.3	569.3
Wholesale Revenues:							
Generation Revenues (a)	—	—	79.4	90.2	—	(4.9)	36.8
Transmission Revenues (b)	154.6	454.7	45.5	10.4	21.4	10.8	42.4
Total Wholesale Revenues	154.6	454.7	124.9	100.6	21.4	5.9	79.2
Other Revenues from Contracts with Customers (c)	8.8	5.0	35.2	26.2	49.2	5.4	6.0
Total Revenues from Contracts with Customers	556.6	459.7	962.4	677.1	989.6	641.6	654.5
Other Revenues:							
Alternative Revenue Programs (d) (e)	(2.0)	3.0	(0.7)	(2.9)	(3.1)	2.6	0.3
Other Revenues (e)	—	—	0.1	2.1	3.0	—	—
Total Other Revenues	(2.0)	3.0	(0.6)	(0.8)	(0.1)	2.6	0.3
Total Revenues	$ 554.6	$ 462.7	$ 961.8	$ 676.3	$ 989.5	$ 644.2	$ 654.8

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $36 million primarily related to the PPA with KGPCo.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $363 million, APCo was $22 million and SWEPCo was $17 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $18 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.

	Nine Months Ended September 30, 2024						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 3,524.2	$ 2,127.7	$ —	$ —	$ —	$ —	$ 5,651.9
Commercial Revenues	2,071.0	1,184.6	—	—	—	—	3,255.6
Industrial Revenues (a)	1,992.5	382.8	—	—	—	(0.6)	2,374.7
Other Retail Revenues	174.9	41.5	—	—	—	—	216.4
Total Retail Revenues	7,762.6	3,736.6	—	—	—	(0.6)	11,498.6
Wholesale and Competitive Retail Revenues:							
Generation Revenues	587.4	—	—	76.5	—	0.1	664.0
Transmission Revenues (b)	371.5	583.2	1,490.8	—	—	(1,255.0)	1,190.5
Renewable Generation Revenues (a)	—	—	—	23.2	—	(4.3)	18.9
Retail, Trading and Marketing Revenues (c)	—	—	—	1,586.2	0.6	(83.7)	1,503.1
Total Wholesale and Competitive Retail Revenues	958.9	583.2	1,490.8	1,685.9	0.6	(1,342.9)	3,376.5
Other Revenues from Contracts with Customers (d)	183.3	148.8	20.1	3.1	153.2	(170.9)	337.6
Total Revenues from Contracts with Customers	8,904.8	4,468.6	1,510.9	1,689.0	153.8	(1,514.4)	15,212.7
Other Revenues:							
Alternative Revenue Programs (a) (e)	(12.5)	17.7	(11.2)	—	—	(15.3)	(21.3)
Other Revenues (a) (f)	(22.4)	15.2	—	(158.9)	(5.2)	4.9	(166.4)
Total Other Revenues	(34.9)	32.9	(11.2)	(158.9)	(5.2)	(10.4)	(187.7)
Total Revenues	$ 8,869.9	$ 4,501.5	$ 1,499.7	$ 1,530.1	$ 148.6	$ (1,524.8)	$ 15,025.0

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $1.2 billion. The affiliated revenue for Vertically Integrated Utilities was $133 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $84 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $112 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.

	Nine Months Ended September 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	$ 3,459.1	$ 2,003.4	$ —	$ —	$ —	$ —	$ 5,462.5
Commercial Revenues	2,029.4	1,121.9	—	—	—	—	3,151.3
Industrial Revenues (a)	2,069.1	503.9	—	—	—	(0.6)	2,572.4
Other Retail Revenues	182.3	37.4	—	—	—	—	219.7
Total Retail Revenues	7,739.9	3,666.6	—	—	—	(0.6)	11,405.9
Wholesale and Competitive Retail Revenues:							
Generation Revenues	498.5	—	—	83.8	—	(0.2)	582.1
Transmission Revenues (b)	348.8	524.3	1,372.0	—	—	(1,229.7)	1,015.4
Renewable Generation Revenues (a)	—	—	—	74.2	—	(5.7)	68.5
Retail, Trading and Marketing Revenues (c)	—	—	—	1,332.2	1.7	(46.7)	1,287.2
Total Wholesale and Competitive Retail Revenues	847.3	524.3	1,372.0	1,490.2	1.7	(1,282.3)	2,953.2
Other Revenues from Contracts with Customers (d)	155.8	157.1	12.7	7.7	113.6	(132.1)	314.8
Total Revenues from Contracts with Customers	8,743.0	4,348.0	1,384.7	1,497.9	115.3	(1,415.0)	14,673.9
Other Revenues:							
Alternative Revenue Programs (a) (e)	(7.5)	(19.5)	6.1	—	—	2.3	(18.6)
Other Revenues (a) (f)	2.2	20.0	—	(272.8)	4.0	(3.6)	(250.2)
Total Other Revenues	(5.3)	0.5	6.1	(272.8)	4.0	(1.3)	(268.8)
Total Revenues	$ 8,737.7	$ 4,348.5	$ 1,390.8	$ 1,225.1	$ 119.3	$ (1,416.3)	$ 14,405.1

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $1.1 billion. The affiliated revenue for Vertically Integrated Utilities was $125 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $47 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Corporate and Other was $87 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.

	Nine Months Ended September 30, 2024						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 562.4	$ —	$ 1,333.7	$ 664.7	$ 1,565.2	$ 647.1	$ 563.2
Commercial Revenues	346.2	—	571.8	465.5	838.4	398.2	413.2
Industrial Revenues (a)	103.3	—	603.5	456.4	279.4	269.9	269.8
Other Retail Revenues	28.7	—	84.3	3.8	12.9	78.2	6.6
Total Retail Revenues	1,040.6	—	2,593.3	1,590.4	2,695.9	1,393.4	1,252.8
Wholesale Revenues:							
Generation Revenues (b)	—	—	235.9	305.6	—	7.0	139.9
Transmission Revenues (c)	511.3	1,450.5	138.3	30.5	71.9	33.0	136.3
Total Wholesale Revenues	511.3	1,450.5	374.2	336.1	71.9	40.0	276.2
Other Revenues from Contracts with Customers (d)	27.4	20.3	71.0	92.3	121.5	30.4	26.0
Total Revenues from Contracts with Customers	1,579.3	1,470.8	3,038.5	2,018.8	2,889.3	1,463.8	1,555.0
Other Revenues:							
Alternative Revenue Program (a) (e)	(2.1)	(15.6)	(6.6)	(0.9)	19.8	(1.8)	(4.2)
Other Revenues (a)	—	—	0.2	(22.7)	15.2	—	—
Total Other Revenues	(2.1)	(15.6)	(6.4)	(23.6)	35.0	(1.8)	(4.2)
Total Revenues	$ 1,577.2	$ 1,455.2	$ 3,032.1	$ 1,995.2	$ 2,924.3	$ 1,462.0	$ 1,550.8

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $118 million primarily related to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $1.2 billion, APCo was $65 million and SWEPCo was $50 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $59 million primarily related 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.

	Nine Months Ended September 30, 2023						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 511.8	$ —	$ 1,192.4	$ 655.5	$ 1,491.6	$ 667.9	$ 647.5
Commercial Revenues	310.3	—	516.2	439.5	811.6	412.7	472.2
Industrial Revenues (a)	109.9	—	575.4	467.6	394.0	320.2	320.3
Other Retail Revenues	26.2	—	78.2	3.8	11.2	86.3	7.6
Total Retail Revenues	958.2	—	2,362.2	1,566.4	2,708.4	1,487.1	1,447.6
Wholesale Revenues:							
Generation Revenues (b)	—	—	223.8	257.7	—	0.3	120.3
Transmission Revenues (c)	464.0	1,338.1	130.8	28.1	60.3	32.0	123.6
Total Wholesale Revenues	464.0	1,338.1	354.6	285.8	60.3	32.3	243.9
Other Revenues from Contracts with Customers (d)	29.2	12.8	60.0	92.6	127.9	14.9	20.9
Total Revenues from Contracts with Customers	1,451.4	1,350.9	2,776.8	1,944.8	2,896.6	1,534.3	1,712.4
Other Revenues:							
Alternative Revenue Program (a) (e)	(6.1)	(1.7)	(0.9)	(8.4)	(13.5)	1.6	(3.9)
Other Revenues (a)	—	—	0.1	2.1	20.1	—	—
Total Other Revenues	(6.1)	(1.7)	(0.8)	(6.3)	6.6	1.6	(3.9)
Total Revenues	$ 1,445.3	$ 1,349.2	$ 2,776.0	$ 1,938.5	$ 2,903.2	$ 1,535.9	$ 1,708.5

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $121 million primarily related to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $1.1 billion, APCo was $64 million and SWEPCo was $43 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $52 million primarily related 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.

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 September 30, 2024. 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	2024	2025-2026	2027-2028	After 2028	Total
			(in millions)		
AEP	$ 23.1	$ 169.0	$ 85.4	$ 24.9	$ 302.4
APCo	4.0	32.1	26.5	11.6	74.2
I&M	1.1	8.8	8.8	4.5	23.2

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have material contract assets as of September 30, 2024 and December 31, 2023.

When the Registrants receive consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have material contract liabilities as of September 30, 2024 and December 31, 2023.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrant Subsidiaries' balance sheets within the Accounts Receivable - Customers line item. The Registrant Subsidiaries' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of September 30, 2024 and December 31, 2023. 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:

	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
September 30, 2024	$ —	$ 131.1	$ 74.0	$ 46.8	$ 66.9	$ 12.5	$ 25.7
December 31, 2023	—	123.2	71.7	44.0	70.1	12.4	27.4

CONTROLS AND PROCEDURES

During the third quarter of 2024, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of September 30, 2024, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of 2024 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, 2023 includes a detailed discussion of risk factors. As of September 30, 2024, the risk factors appearing in AEP's 2023 Annual Report are supplemented and updated as follows:

The occurrence of one or more wildfires could cause tremendous loss, impact the market value and credit ratings of our securities and have a material adverse effect on our financial condition. (Applies to all Registrants)

More frequent and severe drought conditions, extreme swings in amount and timing of precipitation, changes in vegetation, unseasonably warm temperatures, very low humidity, stronger winds and other factors have increased the duration of the wildfire season and the potential impact of an event. AEP's infrastructure is aging and poses risks to safety and system reliability and wildfire mitigation initiatives may not be successful or effective in preventing or reducing wildfire-related events. Wildfires can occur even when effective mitigation procedures are followed. Despite AEP's wildfire mitigation initiatives, a wildfire could be ignited, spread and cause damages, which would subject AEP to significant liability. Other potential risks associated with wildfires include the inability to secure sufficient insurance coverage, uninsured losses or losses in excess of current insurance coverage, increased costs of insurance, regulatory recovery risk, litigation risk, and the potential for a credit downgrade and subsequent additional costs to access capital markets.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

During the three months ended September 30, 2024, 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 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(a)	Aircraft Time Sharing Agreement between AEPSC and William J. Fehrman	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
101.INS	XBRL Instance Document	The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.							
101.SCH	XBRL Taxonomy Extension Schema	X	X	X	X	X	X	X	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	X	X	X	X	X	X	X	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase	X	X	X	X	X	X	X	X
101.LAB	XBRL Taxonomy Extension Label Linkbase	X	X	X	X	X	X	X	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	X	X	X	X	X	X	X	X
104	Cover Page Interactive Data File	Formatted as Inline XBRL and contained in Exhibit 101.							

SIGNATURE

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

AMERICAN ELECTRIC POWER COMPANY, INC.

By: /s/ Kate Sturgess
Kate Sturgess
Controller and Chief Accounting Officer
(Principal Accounting Officer and Authorized Signatory)

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
(Principal Accounting Officer and Authorized Signatory)

Date: November 6, 2024