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

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Quarterly Period Ended **June 30, 2025**
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 July 30, 2025
American Electric Power Company, Inc.	534,794,763
	($6.50 par value)
AEP Texas Inc.	100
	($0.01 par value)
AEP Transmission Company, LLC (a)	NA
Appalachian Power Company	13,499,500
	(no par value)
Indiana Michigan Power Company	1,400,000
	(no par value)
Ohio Power Company	27,952,473
	(no par value)
Public Service Company of Oklahoma	9,013,000
	($15 par value)
Southwestern Electric Power Company	3,680
	($18 par value)

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

NA Not applicable.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF QUARTERLY REPORTS ON FORM 10-Q
June 30, 2025

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 East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP Energy Supply, LLC	A nonregulated holding company for AEP’s competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
AEP OnSite Partners	A division of AEP Energy Supply, LLC that builds, owns, operates and maintains customer solutions utilizing existing and emerging distributed technologies.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary. AEP Texas engages in the transmission and distribution of electric power to retail customers in west, central and southern Texas.
AEP Transmission Holdco / AEPTHCo	AEP Transmission Holding Company, LLC, a subsidiary of AEP, an intermediate holding company that owns transmission operations joint ventures and AEPTCo.
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 Midwest Transmission Holdings and 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. APCo engages in the generation, transmission and distribution of electric power to retail customers in the southwestern portion of Virginia and southern West Virginia.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding, LLC, a wholly-owned subsidiary of APCo and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
APSC	Arkansas Public Service Commission.
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.
CEO	Chief Executive Officer.
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.
Cost Recovery Funding	KPCo Cost Recovery Funding, LLC, a wholly-owned subsidiary of KPCo and consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to plant retirement costs, deferred storm costs, deferred purchased power expenses, under-recovered purchased power rider costs and issuance-related expenses.

Term	Meaning
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, DCC Fuel XX and DCC XXI 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.
Diversion	Diversion, acquired in December 2024, consists of 201 MWs of wind generation in Texas.
Eastern Region	AEP's eastern service territory includes the areas where APCo, I&M, KGPCo, KPCo, OPCo and WPCo engage in the generation, transmission and distribution of electric power to customers.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
ELG	Effluent Limitation Guidelines.
ENEC	Expanded Net Energy Cost.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESA	Electric Service Agreement.
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	Generally Accepted Accounting Principles in the United States of America.
GHG	Greenhouse gas.
G&M	Generation & Marketing.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary. I&M engages in the generation, transmission and distribution of electric power to retail customers in northern and eastern Indiana and southwestern Michigan.
IMTCo	AEP Indiana Michigan Transmission Company, Inc.
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary. KGPCo provides electric service to retail customers in Kingsport, Tennessee and eight neighboring communities in northeastern Tennessee.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary. KPCo engages in the generation, transmission and distribution of electric power to retail customers in eastern Kentucky.
KPSC	Kentucky Public Service Commission.

Term	Meaning
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
Midwest Transmission Holdings	Midwest Transmission Holdings, LLC, a subsidiary of AEPTCo Parent that owns all of the issued and outstanding stock of IMTCo and OHTCo.
MISO	Midcontinent Independent System Operator.
Mitchell Plant	A two unit, 1,560 MW coal-fired power plant located in Moundsville, West Virginia. The plant is jointly owned by KPCo and WPCo.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NAAQS	National Ambient Air Quality Standards.
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.
ODEQ	Oklahoma Department of Environmental Quality.
OHTCo	AEP Ohio Transmission Company, Inc.
OPCo	Ohio Power Company, an AEP electric utility subsidiary. OPCo engages in the transmission and distribution of electric power to retail customers in Ohio.
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	Power Purchase Agreement.
PSA	Purchase and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary. PSO engages in the generation, transmission and distribution of electric power to retail customers in eastern and southwestern Oklahoma.
PTC	Production Tax Credit.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.

Term	Meaning
Restoration Funding	AEP Texas Restoration Funding, LLC, a wholly-owned subsidiary of AEP Texas and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Texas primarily caused by Hurricane Harvey.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, jointly owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated VIE for AEP and SWEPCo.
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.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, which are geographically aligned with AEP's existing utility operating companies.
Storm Recovery Funding	SWEPCo Storm Recovery Funding, LLC, a wholly-owned subsidiary of SWEPCo and consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to storm restoration in Louisiana.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary. SWEPCo engages in the generation, transmission and distribution of electric power to retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas.
SWTCo	AEP Southwestern Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
T&D	Transmission and Distribution Utilities.
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. Transource Energy is 86.5% owned by AEP.
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.
Valley Link	Valley Link Transmission Company, LLC, a holding company formed by Transource Energy, affiliates of Dominion Energy and FirstEnergy in 2024.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
VIU	Vertically Integrated Utilities.

Term	Meaning
Western Region	AEP's western service territory includes the areas where AEP Texas, PSO and SWEPCo engage in the generation, transmission and distribution of electric power to customers.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary. WPCo provides electric service to retail customers in northern West Virginia.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements, and for the Registrants other than Parent, this report 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, trade restrictions or changes in trade policy.
- Inflationary or deflationary interest rate trends.
- New legislation adopted in the states in which we operate that alters the regulatory framework or that prevents the timely recovery of costs and investments.
- Volatility and disruptions in financial markets precipitated by any cause, including fiscal and monetary policy, 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.
- Changing demand for electricity, including large load contractual commitments for interconnection.
- The risks and uncertainties associated with wildfires, including damages caused by wildfires, the extent of each Registrant’s liability in connection with wildfires, investigations and outcomes associated with legal proceedings, demands or similar actions, inability to recover wildfire costs through insurance or through rates and the impact on financial condition and the reputation of each Registrant.
- The impact of extreme weather conditions, natural disasters and catastrophic events such as storms, wildfires and drought conditions 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, wildfires 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, to recover all related costs and to earn a reasonable return.
- The disruption of AEP’s business operations due to impacts of 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 modified requirements related to 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 tax legislation or associated Department of Treasury guidance, including potential changes to existing tax incentives, on capital plans, 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 and recover operation, maintenance and development project 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 development, adoption, and use of artificial intelligence by us, our customers and our third party vendors and 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 and nuclear decommissioning trust funds and a captive insurance entity 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 Annual Report on Form 10-K for the fiscal year ended December 31, 2024 (the “2024 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 RESULTS OF OPERATIONS

Second Quarter of 2025 Compared to Second Quarter of 2024

Earnings Attributable to AEP Common Shareholders increased from $340 million in 2024 to $1.2 billion in 2025 primarily due to:

- The favorable impact from the receipt of a June 2025 FERC order related to the treatment of NOLCs in transmission formula rates. See "June 2025 FERC Orders on NOLCs in Transmission Formula Rates" section below for additional information.
- A revenue refund provision recorded in 2024 associated with the Turk Plant and SWEPCo's 2012 Texas Base Rate Case.
- An increase in operating expenses recorded in 2024 due to the Federal EPA's revised CCR rule finalized in 2024.
- An increase in operating expenses recorded in 2024 due to the voluntary severance program that occurred in the second quarter of 2024.
- Favorable rate proceedings in AEP's various jurisdictions.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

Earnings Attributable to AEP Common Shareholders increased from $1.3 billion in 2024 to $2.0 billion in 2025 primarily due to:

- The favorable impact from the receipt of a June 2025 FERC order related to the treatment of NOLCs in transmission formula rates. See "June 2025 FERC Orders on NOLCs in Transmission Formula Rates" section below for additional information.
- A revenue refund provision recorded in 2024 associated with the Turk Plant and SWEPCo's 2012 Texas Base Rate Case.
- An increase in operating expenses recorded in 2024 due to the Federal EPA's revised CCR rule finalized in 2024.
- An increase in operating expenses recorded in 2024 due to the voluntary severance program that occurred in the second quarter of 2024.
- An increase in sales volumes driven by favorable weather.
- Favorable rate proceedings in AEP's various jurisdictions.

These increases were partially offset by:

- The favorable impact from the receipt of PLRs in 2024 related to the treatment of NOLCs in retail ratemaking. See "NOLCs in Retail Jurisdictions - IRS PLRs" section below for additional information.

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

Non-GAAP Financial Measures

AEP reports its financial results in accordance with GAAP by using earnings (loss) attributable to AEP common shareholders as stated above. AEP supplements the reporting of financial information determined in accordance with GAAP with certain non-GAAP financial measures including operating earnings. Operating earnings, which could differ from GAAP earnings, exclude certain gains and losses and other specified items, including mark-to-market adjustments from commodity hedging activities and other items as set forth in the reconciliation below. Management believes these are not indicative of AEP's ongoing performance.

This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of AEP's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. These non-GAAP financial measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations.

Reconciliation of Reported GAAP Earnings to Operating Earnings

The following tables present a reconciliation of operating earnings to the most directly comparable GAAP measure.

	Three Months Ended June 30, 2025							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Reported GAAP Earnings	$1,225.8	$ 121.1	$ 555.8	$ 106.9	$ 124.1	$ 102.8	$ 63.7	$ 115.6
Adjustments to Reported GAAP Earnings (a):								
Mark-to-Market Impact of Commodity Hedging Activities (b)	20.0	—	—	—	(9.6)	—	—	—
FERC NOLC Order (c)	(480.1)	—	(353.9)	(28.9)	(35.6)	0.2	(4.0)	(54.1)
Total Specified Items	(460.1)	—	(353.9)	(28.9)	(45.2)	0.2	(4.0)	(54.1)
Operating Earnings	$ 765.7	$ 121.1	$ 201.9	$ 78.0	$ 78.9	$ 103.0	$ 59.7	$ 61.5

	Three Months Ended June 30, 2024							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Reported GAAP Earnings (Loss)	$ 340.3	$ 128.4	$ 175.7	$ 58.3	$ 35.2	$ 18.4	$ 36.3	$ (70.1)
Adjustments to Reported GAAP Earnings (Loss) (a):								
Mark-to-Market Impact of Commodity Hedging Activities (b)	(7.2)	—	—	—	(3.5)	—	—	—
Remeasurement of Excess ADIT Regulatory Liability (d)	(12.2)	—	—	—	(12.3)	—	—	—
Provision for Refund - Turk Plant (e)	126.4	—	—	—	—	—	—	126.4
Pending Sale of AEP OnSite Partners (f)	10.4	—	—	—	—	—	—	—
Severance Charges (g)	93.6	15.6	8.2	20.3	11.1	11.6	7.7	12.7
Federal EPA Coal Combustion Residuals Rule (h)	110.7	—	—	—	10.6	41.3	(4.0)	—
Total Specified Items	321.7	15.6	8.2	20.3	5.9	52.9	3.7	139.1
Operating Earnings	$ 662.0	$ 144.0	$ 183.9	$ 78.6	$ 41.1	$ 71.3	$ 40.0	$ 69.0

(a) Excluding tax related adjustments, all items presented in the table are tax adjusted at the statutory rate unless otherwise noted.
(b) Represents the impact of mark-to-market economic hedging activities.
(c) Represents the impact of the FERC NOLC Order for years 2021-2024.
(d) Represents the impact of the remeasurement of Excess ADIT in Michigan.
(e) Represents a provision for revenue refunds on certain capitalized costs associated with the Turk Plant.
(f) Represents the loss on the expected sale of AEP OnSite Partners.
(g) Represents employee severance charges.
(h) Represents the impact of the Federal EPA Revised CCR Rule.

	Six Months Ended June 30, 2025							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Reported GAAP Earnings	$2,026.0	$ 222.7	$ 767.3	$ 271.5	$ 181.6	$ 165.8	$ 91.2	$ 164.1
Adjustments to Reported GAAP Earnings (a):								
Mark-to-Market Impact of Commodity Hedging Activities (b)	6.0	—	—	—	16.2	—	—	—
Sale of AEP OnSite Partners (c)	9.4	—	—	—	—	—	—	—
Impact of Ohio Legislation (d)	27.7	—	—	—	—	27.7	—	—
FERC NOLC Order (e)	(480.1)	—	(353.9)	(28.9)	(35.6)	0.2	(4.0)	(54.1)
Total Specified Items	(437.0)	—	(353.9)	(28.9)	(19.4)	27.9	(4.0)	(54.1)
Operating Earnings	$1,589.0	$ 222.7	$ 413.4	$ 242.6	$ 162.2	$ 193.7	$ 87.2	$ 110.0

	Six Months Ended June 30, 2024							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Reported GAAP Earnings	$1,343.4	$ 208.1	$ 356.9	$ 194.8	$ 180.2	$ 89.0	$ 108.3	$ 138.0
Adjustments to Reported GAAP Earnings (a):								
Mark-to-Market Impact of Commodity Hedging Activities (b)	(59.0)	—	—	—	17.0	—	—	—
Remeasurement of Excess ADIT Regulatory Liability (f)	(44.6)	—	—	—	(12.3)	—	—	(32.3)
Impact of NOLC on Retail Ratemaking (g)	(259.6)	—	—	—	(69.1)	—	(56.5)	(134.0)
Disallowance - Dolet Hills Power Station (h)	11.1	—	—	—	—	—	—	11.1
Provision for Refund - Turk Plant (i)	126.4	—	—	—	—	—	—	126.4
Pending Sale of AEP OnSite Partners (j)	10.4	—	—	—	—	—	—	—
Severance Charges (k)	93.6	15.6	8.2	20.3	11.1	11.6	7.7	12.7
Federal EPA Coal Combustion Residuals Rule (l)	110.7	—	—	—	10.6	41.3	—	—
Total Specified Items	(11.0)	15.6	8.2	20.3	(42.7)	52.9	(48.8)	(16.1)
Operating Earnings	$1,332.4	$ 223.7	$ 365.1	$ 215.1	$ 137.5	$ 141.9	$ 59.5	$ 121.9

(a) Excluding tax related adjustments, all items presented in the table are tax adjusted at the statutory rate unless otherwise noted.
(b) Represents the impact of mark-to-market economic hedging activities.
(c) Represents an adjustment to the estimated loss on the sale of AEP OnSite Partners as a result of the contractual working capital true-up.
(d) Represents the estimated reduction in regulatory assets for OVEC-related purchased power costs as a result of approved legislation in Ohio in April 2025.
(e) Represents the impact of the FERC NOLC Order for years 2021-2024.
(f) Represents the impact of the remeasurement of Excess ADIT in Arkansas and Michigan.
(g) Represents the impact of receiving IRS PLRs related to NOLCs in retail ratemaking on I&M, PSO and SWEPCo. Amount includes a reduction in Excess ADIT and activity related to prior periods.
(h) Represents the impact of a disallowance recorded at SWEPCo on the remaining net book value of the Dolet Hills Power Station as a result of an LPSC approved settlement agreement in April 2024.
(i) Represents a provision for revenue refunds on certain capitalized costs associated with the Turk Plant.
(j) Represents the loss on the expected sale of AEP OnSite Partners.
(k) Represents employee severance charges.
(l) Represents the impact of the Federal EPA Revised CCR Rule.

RECENT DEVELOPMENTS AND TRANSACTIONS

NOLCs in Transmission Formula Rates - June 2025 FERC Orders

In June 2025, the FERC issued two orders, partially reversing its January 2024 decisions on the basis of IRS PLRs accepted into the record, and concluding that the accelerated depreciation-related NOLC adjustments should be included in rate base and should also be included in the computation of Excess ADIT regulatory liabilities to be refunded to customers. As a result of the June 2025 FERC orders, the Registrants recognized revenues, with interest, attributable to accelerated depreciation-related NOLCs included in transmission formula rates for years 2021 through 2025 and reduced Excess ADIT regulatory liabilities. The impact of the orders resulted in a $499 million increase in Earnings Attributable to AEP Common Shareholders for the three and six months ended June 30, 2025. See the table below and the "FERC 2021 PJM and SPP Transmission Formula Rate Challenge" section of Note 4 for additional information.

Company	Increase (Decrease) in Pretax Income (a)	Decrease in Income Tax Expense (b)	Increase in Noncontrolling Interest (c)	Increase in Net Income
		(in millions)		
APCo	$ 8.0	$ 21.4	$ —	$ 29.4
I&M	16.8	27.8	—	44.6
PSO	(12.4)	15.6	—	3.2
SWEPCo	16.8	38.9	—	55.7
AEPTCo	214.3	203.2	(55.2)	362.3
Other (d)	(2.1)	5.9	—	3.8
AEP Total	$ 241.4	$ 312.8	$ (55.2)	$ 499.0

(a) Primarily represents the reversal of revenue refund provisions for years 2021-2025, partially offset by an increase in affiliated transmission expenses.
(b) Primarily relates to a $384 million remeasurement of Excess ADIT regulatory liabilities, partially offset by $71 million of tax expense on favorable pretax income.
(c) The noncontrolling interest relates to IMTCo and OHTCo. See "Noncontrolling Interest in OHTCo and IMTCo" section of Note 6 for additional information.
(d) Includes KGPCo, KPCo, OPCo and WPCo.

NOLCs in Retail Jurisdictions - IRS PLRs

AEP's utility subsidiaries have made rate filings with state commissions to transition to stand-alone treatment of NOLCs in retail ratemaking. 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 ratemaking 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.

The table below provides a summary of the status of the transition to stand-alone treatment of NOLCs in retail ratemaking for each AEP utility subsidiary.

Company (a)	Jurisdiction		Status
APCo	Virginia		Approved
APCo/WPCo	West Virginia	(b)	Pending
I&M	Indiana		Approved
I&M	Michigan		Approved
KGPCo	Tennessee		Approved
KPCo	Kentucky	(c)	Pending
PSO	Oklahoma	(c)	Approved, subject to refund
SWEPCo	Arkansas	(d)	Pending
SWEPCo	Louisiana	(c)	Pending
SWEPCo	Texas		Approved, subject to refund

(a) AEP Texas and OPCo do not have NOLCs on a stand-alone basis.
(b) Pending in 2024 West Virginia Base Rate Case.
(c) Awaiting receipt of jurisdiction specific IRS PLR.
(d) Pending in 2025 Arkansas Base Rate Case.

Beginning in the second quarter of 2024 and continuing until the NOLC revenue requirement is in rates, AEP is recognizing additional regulatory assets related to revenue requirement amounts to be collected from customers. As of June 30, 2025, AEP has NOLC regulatory assets of $114 million on its balance sheet.

Noncontrolling Interest in OHTCo and IMTCo (Applies to AEP and AEPTCo)

In January 2025, AEP announced a partnership whereby nonaffiliated entities will acquire a 19.9% noncontrolling interest in OHTCo and IMTCo for $2.82 billion. The transaction closed in June 2025 and AEP received cash proceeds of approximately $2.78 billion, net of transaction costs. Net proceeds will be used to help finance AEP's $54 billion capital plan for 2025-2029, announced in November 2024, driven by transmission and distribution infrastructure upgrades and new generation to support anticipated load growth. See "Noncontrolling Interest in OHTCo and IMTCo" section of Note 6 for additional information.

PSO New Generation Resources

In the second quarter of 2025, PSO expanded its generation portfolio by acquiring three power generation facilities, as listed below, for a total of $1.4 billion. See "Acquisitions" section of Note 6 for additional information.

Plant Name	Fuel Type	Location	Acquisition Date	Generating Capacity
				(in MWs)
Green Country	Natural Gas	Jenks, OK	June 2025	795
Pixley	Solar	Barber County, KS	May 2025	189
Flat Ridge IV	Wind	Kingman and Harper Counties, KS	June 2025	135
Total				1,119

Kentucky Securitization

In June 2025, KPCo issued $478 million of securitization bonds to recover $500 million of regulatory assets, including $311 million of plant retirement costs, $79 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, $56 million of under-recovered purchased power rider costs, $51 million of deferred purchased power expenses and $3 million of issuance-related expenses, including KPSC advisor expenses. The net bond proceeds of $478 million also included $6 million for non-utility issuance costs and a $29 million offset for net present value of return on accumulated deferred income taxes related to KPCo's Decommissioning Rider as ordered by the KPSC.

New Legislation

Ohio Legislation

Ohio House Bill 15 (HB 15) was approved by the Ohio legislature in April 2025 and signed into law by the Governor of Ohio in May 2025. HB 15 is effective beginning August 14, 2025 and (a) alters rate-setting mechanisms by replacing ESPs with triennial base rate cases based on a three-year forecasted test period, effective with the end of OPCo's previously approved ESP which ends in May 2028, (b) eliminates OPCo's ability to recover from, or refund to, customers the difference between purchased power expenses from OVEC and the market revenues OPCo receives from that purchased power as of the effective date of the law and (c) repeals the statute that permits electric distribution utilities, including OPCo, to execute contracts to provide customer-sited renewable generation service such as fuel cell technology or other renewable resources prospectively.

As a result of this legislation, in the first quarter of 2025, OPCo recorded a $35 million estimated reduction to its OVEC-related purchased power regulatory asset for deferred net costs that are no longer probable of future recovery. Management is unable to predict the future impact to net income, cash flows and financial condition arising from the future changes in OPCo's rate setting mechanisms and the elimination of OPCo's ability to recover from, or refund to, customers the difference between purchased power expenses from OVEC and the market revenues OPCo receives from that purchased power.

Texas Legislation

On June 20, 2025, Texas House Bill 5247 (HB 5247) was signed into law by the Governor of Texas and became effective. The bill establishes a tracking mechanism for qualifying electric utilities to file annual interim rate adjustments for cost recovery of certain transmission and distribution capital expenditures. On June 27, 2025, AEP Texas filed with the PUCT notice of qualification and election to use the tracking mechanism permitted by HB 5247. Qualifying electric utilities under HB 5247 consist of utilities that: (a) operate solely in ERCOT, (b) have been identified by the PUCT as having responsibility for constructing transmission infrastructure as part of ERCOT's Permian Basin Reliability Plan and (c) make annual capital expenditures in transmission and distribution that exceed 300% of annual depreciation. Based on those requirements, AEP Texas is a qualifying electric utility and SWEPCo and ETT are not qualifying electric utilities.

The tracking mechanism permits a qualifying electric utility to defer all or a portion of costs associated with its eligible transmission and distribution capital investments, including depreciation expense and carrying costs, as a regulatory asset. The tracking mechanism is available through 2035 and is an alternative to the existing capital tracking mechanisms in Texas. Deferred costs will be recovered through interim rate updates over a period not to exceed 18 months and earn a return until recovered. As a result of the new legislation, AEP Texas deferred approximately $25 million of eligible costs through June 2025 as a regulatory asset. Investments included in the tracking mechanism and the existing capital tracker filings remain subject to prudency review in the utility's next base rate review before the PUCT. If any of these deferred costs are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

Oklahoma Legislation

Effective August 28, 2025, in accordance with Oklahoma Senate Bill 998 (SB 998), a public utility that elects to defer costs may defer up to 90% of all depreciation expenses and returns associated with qualifying electric plants to a regulatory asset, provided the utility has notified the OCC of its election to do so. SB 998 excludes deferral of depreciation expense related to transmission plant and/or new electric generating units. Deferred costs will be recovered through base rates over a 20-year period and earn a return until recovered. SB 998 also allows for expedited recovery of new gas plant investments. Although SB 998 is expected to be favorable, management does not expect it to have a material impact on 2025 net income, cash flows and financial condition.

Federal Tax Legislation

On July 4, 2025, President Trump signed H.R. 1 into law, commonly known as the One Big Beautiful Bill Act (OBBBA). Most notably for AEP, this budget reconciliation legislation modifies and accelerates the phase out of wind and solar PTCs and ITCs, adds new restrictions to guard against certain foreign ownership or influence with respect to otherwise credit-eligible projects and makes 100% bonus depreciation permanent for our non-regulated entities. With the exception of bonus depreciation, this legislation is prospective and has no material impact on the current period financial statements. Following enactment of the legislation, on July 7, 2025, the President issued an Executive Order directing the Department of Treasury to issue new and revised wind and solar tax credit guidance within 45 days, which could impose further practical limits on the development of wind and solar projects. In addition to this potential near term guidance, additional significant guidance from the Department of Treasury and the IRS is expected on the tax provisions included in the OBBBA. AEP will continue to monitor any issued guidance and evaluate the impact on future net income, cash flows and financial condition.

Forward Sale of Equity

In March 2025, AEP entered into separate forward sale agreements with non-affiliate forward purchasers relating to 22,549,020 shares of AEP's common stock at an initial price of $102.00 per share, exclusive of an underwriting discount equal to $2.244 per share. Except in certain specified circumstances that would require physical share settlement, AEP may elect to settle the forward sale transaction by means of physical, cash or net share settlement. The timing of the settlement of the forward sale agreements is also at AEP's discretion, and management currently expects settlement to occur on or prior to December 31, 2026. To the extent the forward sale agreements are physically settled, AEP will issue common stock to the forward purchasers and receive cash proceeds based on the applicable forward sale price on the settlement date as defined in the forward sale agreements. As of June 30, 2025, AEP expects approximately $2.25 billion of net cash proceeds from the full physical settlement of the forward sale agreements and management anticipates using any future proceeds for general corporate purposes, which may include capital contributions to utility subsidiaries, acquisitions or repayment of debt. The forward sale transactions will be classified as equity transactions because they are indexed to AEP's common stock and physical settlement is within AEP's control.

Valley Link Investment (Applies to AEP and Transource Energy)

In 2024, Transource Energy and affiliates of Dominion Energy and FirstEnergy formed Valley Link Transmission, LLC to participate in PJM's 2024 Regional Transmission Expansion Plan competitive process. Valley Link proposed regional electric transmission upgrades for PJM's consideration during PJM's 2024 Reliability Window 1. In February 2025, PJM selected the upgrades proposed by Valley Link to address forecasted reliability requirements. The projects awarded by PJM are estimated to cost approximately $3 billion and Transource Energy's share of this investment is estimated to be $1.1 billion.

In March 2025, Valley Link's subsidiaries, including Valley Link Transmission Maryland, LLC, Valley Link Transmission Virginia, LLC and Valley Link Transmission West Virginia, LLC, submitted to FERC a request for acceptance of formula rates for each company, consisting of a formula rate template and implementation protocols, effective May 2025. The filing also requested approval of Federal Power Act Section 219 transmission incentive rate treatments for the projects awarded by PJM to the Valley Link subsidiaries. In May 2025, the FERC issued an order accepting the formula rate, granting the incentives for: (a) recovery of abandonment costs if the project is cancelled for reasons beyond Valley Link's control, (b) inclusion of CWIP in rates while the project is in development, (c) regulatory asset treatment for pre-commercial costs and (d) a 50-basis point ROE adder due to participation in an RTO. The order also initiated settlement proceedings to determine the companies' base ROE, hypothetical capital structures, formula rate template language and depreciation rates.

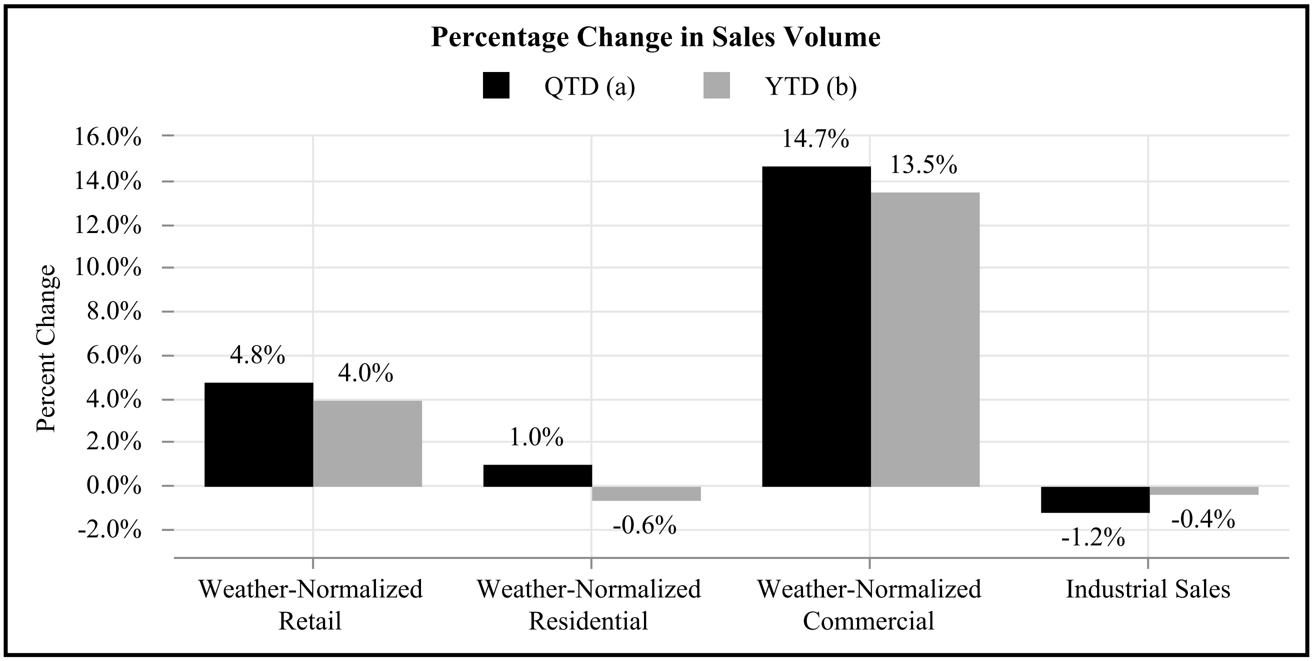
Fuel Cell Agreement

In November 2024, AEP executed a purchase agreement to acquire 100 MWs of solid oxide fuel cells with an option to acquire up to one gigawatt in total by the end of 2025. AEP, through its subsidiaries, is offering data centers and other large customers this custom solution to support their growing energy needs while grid infrastructure enhancements are completed to accommodate demand. As of June 30, 2025, OPCo has signed two contracts totaling approximately 98 MW for electricity service from fuel cells. In February 2025, OPCo requested PUCO approval of those two contracts. The PUCO approved the contracts in May 2025.

Ohio House Bill 15 repeals the statute that permits electric distribution utilities, including OPCo, to execute contracts to provide customer-sited renewable generation service such as fuel cell technology or other renewable resources after August 14, 2025, but grandfathered the two existing PUCO approved contracts. See "Ohio Legislation" section above for additional information.

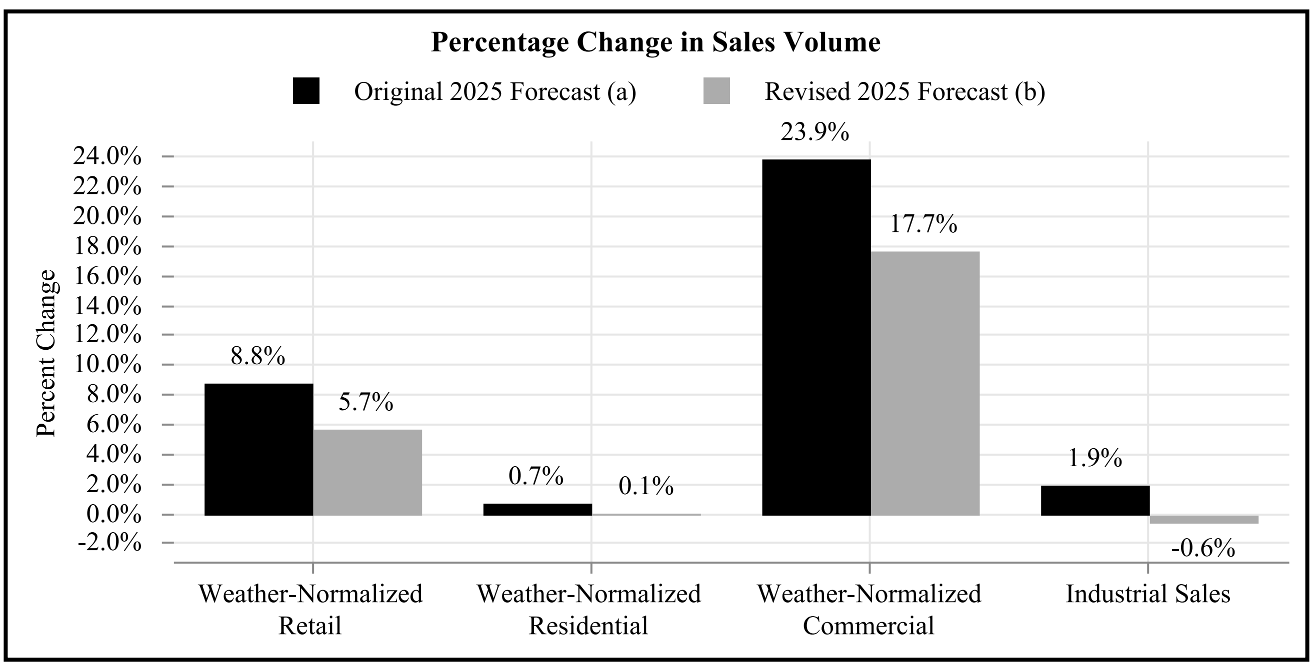
Customer Demand

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. The increase in commercial sales volumes was primarily due to new data processor loads. The decline in industrial sales volumes is primarily due to the continuing impact of elevated interest rates and tariff-related headwinds. The year-to-date decline in weather-normalized residential sales volumes is primarily due to energy efficiency and continuing inflationary pressures.



(a) Percentage change for the three months ended June 30, 2025 as compared to the three months ended June 30, 2024.
(b) Percentage change for the six months ended June 30, 2025 as compared to the six months ended June 30, 2024.

The table below summarizes AEP's revised 2025 forecasted retail sales volumes as compared to the forecast presented in the 2024 10-K. The decline in forecasted 2025 sales volumes is primarily due to the continuing impact of elevated interest rates, tariff-related headwinds and slower than anticipated load ramps among certain large commercial customers.



(a) As presented in the 2024 AEP 10-K: Forecasted percentage change for the year ended December 31, 2025 compared to the year ended December 31, 2024.
(b) Revised: Forecasted percentage change for the year ended December 31, 2025 compared to the year ended December 31, 2024. The revised 2025 forecast reflects year-to-date actual results plus six months of forecasted values based on underlying economic and demographic trends.

Inflation, Tariffs on International Trade and Supply Chain Disruption

The Registrants have experienced certain supply chain constraints driven by several factors including international tensions and the ramifications of regional conflict, inflation, increased energy infrastructure construction to meet energy intensive customer demands, labor shortages in certain trades and shortages in the availability of certain raw materials. These supply chain constraints 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.

The U.S. administration has taken executive action and proposed additional measures intended to alter the U.S. approach to international trade policy, the terms of certain existing bilateral or multi-lateral trade agreements and trading arrangements with foreign countries. Such changes to U.S. international trade policy, and any retaliatory trade measures that foreign governments may take in response, including the imposition of tariffs, sanctions, export or import controls, or other measures that restrict international trade, or the threat of such actions, could result in additional increases in the cost of certain goods, services and cost of capital and further extend lead times.

Management has implemented risk mitigation strategies seeking to limit the impacts of these supply chain constraints. Forecasted load growth and tariffs on international trade may further impact supply chains in the future by increasing demand pressures for certain materials and services, thereby requiring additional risk mitigation strategies to be deployed.

A prolonged continuation or a further increase in the severity of inflationary pressure, heightened geopolitical disruptions and tariffs on international trade could result in additional supply chain disturbances. These events could lead to 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.

Large Load/Data Center Tariffs

Certain AEP utility subsidiaries have made rate filings with state commissions to establish new tariffs for data centers and other large load customers. These new tariffs are generally designed to extend the duration of ESAs, implement higher minimum demand charges and address changes in contract capacity and termination of service. The table below provides a summary of the status of these new data center and large load tariffs.

Jurisdiction	Large Load Tariff	Status	Customer Eligibility
Indiana	Industrial Power	Approved	New load of 150 MW or more/70 MW for individual site
Kentucky	Industrial General Service	Approved	New commercial or industrial load of 150 MW or more
Ohio	Data Center	Approved	New data center load of 25 MW or more
Virginia	Large Power Service	Pending	New load of 150 MW or more/100 MW for individual site
West Virginia	Large Capacity/Industrial Power	Approved	New load of 200 MW or more

In June 2025, Texas Senate Bill 6 (SB 6) became effective and was signed into law by the Governor of Texas. SB 6 establishes standards for connecting large load customers within ERCOT in a way that supports business development in Texas while minimizing the potential for stranded infrastructure costs. The new legislation provides authority and discretion to the PUCT to provide additional rulemaking related to implementing and enforcing its mandates.

New Generation to Support Reliability

The growth of AEP's regulated generation portfolio reflects the company's commitment to meet increasing customer demand for power while balancing cost and reliability.

Significant Approved Renewable Generation Filings

AEP has received regulatory approvals from various state regulatory commissions to acquire approximately 1,979 MWs of owned renewable generation facilities, totaling approximately $4.7 billion. The estimated cost of these facilities is included in the Budgeted Capital Expenditures disclosure included in the Financial Condition section below. In addition, AEP has received regulatory approvals for 637 MWs of renewable PPAs. The following table summarizes regulatory approvals received for active renewable projects as of June 30, 2025:

Company	Generation Type	Expected Commercial Operation	Owned/PPA	Generating Capacity (a)
				(in MWs)
APCo	Solar	2025-2027	PPA	184
APCo (a)	Wind	2025-2026	Owned	344
I&M	Solar	2026-2027	PPA	280
I&M	Solar	2027	Owned	469
I&M	Wind	2026	PPA	100
PSO (b)	Solar	2025-2026	Owned	150
PSO (b)	Wind	2025-2026	Owned	418
SWEPCo	Solar	2025	PPA	73
SWEPCo	Wind	2025	Owned	598
Total Approved Renewable Projects				2,616

(a) APCo has issued notice to proceed for the construction of all 344 MWs of wind capacity.
(b) PSO has issued notices to proceed for the construction of two wind facilities for a total capacity of 418 MWs. These facilities are part of the approved projects contemplated within PSO's 568 MWs of total new renewable generation.
(c) The recently enacted OBBBA legislation is not expected to impact the qualification of federal tax incentives for these generation facilities.

Natural Gas Generation

In December 2024, SWEPCo filed an application for a Certificate of Convenience and Necessity (CCN) with the APSC, LPSC and PUCT for the construction of the Hallsville Natural Gas Plant (450 MWs) and the fuel conversion of Welsh Plant, Units 1 and 3 to natural gas. In the application for the CCN, SWEPCo seeks to site the Hallsville Natural Gas Plant at the location of the now-retired Pirkey Power Plant. If approved, the projects will help SWEPCo address increasing SPP capacity requirements. SWEPCo estimates the combined capital cost of these projects is approximately $723 million and the projects would be placed in service between November 2027 and May 2028.

In February 2025, I&M entered into a PSA to acquire an 870 MW combined-cycle power generation facility located in Ohio. In April 2025, I&M submitted a FERC 203 application for the acquisition. If approved, the project will help I&M address increasing capacity and power needs. I&M expects to close on the transaction in the first quarter of 2026.

Significant Generation Requests for Proposal (RFP)

The table below includes active RFPs issued for both owned and purchased power generation. Projects selected will be subject to regulatory approval.

Company	Issuance Date	Projected In-Service Dates	Generating Capacity
			(in MWs)
PSO (a)	November 2023	2027/2028	1,500
I&M (b)	September 2024	2029	4,000
APCo (c)	May 2024	2028	1,100
APCo (d)	May 2025	2029	800
APCo (e)	May 2025	2029	300
Total Significant RFPs			7,700

(a) RFP is seeking 1,500 MW of SPP accredited capacity and associated energy through an all-source solicitation.
(b) RFP is seeking up to 4,000 MW (cumulatively) from intermittent (wind, solar), non-intermittent (dispatchable), and emerging technology resources.
(c) RFP is seeking wind, solar, stand-alone battery energy storage systems and Renewable Energy Certificates.
(d) RFP is seeking 800 MW of wind, solar, and/or co-located or stand-alone battery energy storage systems PSAs.
(e) RFP is seeking 300 MW of wind, solar, hydro, or geothermal PPAs.

Capacity Purchase Agreements

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 under contract as of June 30, 2025, by year, for the five year period 2025-2029:

	I&M		PSO		SWEPCo	
	Natural Gas	Wind	Natural Gas	Wind	Natural Gas	Wind
Delivery Start Year	(in MWs)					
2025	—	—	760	27	150	91
2026	615	73	460	86	150	100
2027	777	—	410	86	300	100
2028	1,000	—	410	—	450	—
2029	1,000	—	410	—	450	—

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 financial condition.

The following table summarizes the Registrants' pending base rate case proceedings. See Note 4 - Rate Matters for additional information.

Company	Jurisdiction	Filing Date	Annual Base Revenue Increase Request (in millions)	Requested ROE
APCo	West Virginia	November 2024	$ 224.0	10.8%
SWEPCo	Arkansas	March 2025	114.0	10.9%
OPCo	Ohio	May 2025	97.4	10.9%

Other Significant Regulatory Matters

2025 West Virginia Securitization Filing

In March 2025, APCo and WPCo (the Companies) requested to finance, through the issuance of securitization bonds, approximately $2.4 billion of West Virginia jurisdictional undepreciated property balances and regulatory assets including: (a) $321 million of the Companies' remaining combined unrecovered ENEC balance related to costs incurred through February 28, 2023, (b) $1.7 billion of undepreciated West Virginia jurisdictional plant balances as of December 31, 2022 for the Amos, Mitchell and Mountaineer Plants, (c) $237 million of environmental costs previously approved for recovery through a separate West Virginia surcharge and (d) $118 million of West Virginia jurisdictional major storm operation and maintenance costs deferred as of June 2024.

The Companies also proposed that the WVPSC consider approving the securitization of additional ENEC under-recovered costs, such as those costs approved in the 2024 ENEC case, as well as additional deferred West Virginia jurisdictional major storm operation and maintenance costs, such as those associated with Hurricane Helene and Winter Storms Blair, Harlow and Jett.

In May 2025, WVPSC staff recommended that the $321 million ENEC under-recovery and $118 million storm cost deferral be excluded from the securitization. Staff recommended that the $321 million ENEC under-recovery continue to be recovered through the current ENEC rates and the storm cost deferral be recovered without a carrying charge over five years through base rates to be implemented in August 2025. A hearing was held in July 2025 and an order is expected in the third quarter of 2025.

2025 Virginia Securitization Legislation and Securitization Filing

In March 2025, the Governor of Virginia signed into law amendments to the Virginia utility retail base rate and rider rate case processes applicable to APCo as well as definitions of assets that APCo may request for securitization in future filings, effective July 1, 2025. This legislation will move future APCo Virginia biennial base rate filing due dates from March 31st to May 31st, with a final Virginia SCC order to be issued on these future filings no later than January 15th of the subsequent year and resulting updated base rates implemented no earlier than March 1st. This legislation prohibits APCo from increasing Virginia retail rates during the winter heating months of November through February. Finally, this legislation also allows APCo to file with the Virginia SCC, no earlier than July 1, 2025, a request seeking permission to securitize major storm costs incurred starting January 1, 2024 as well as the remaining December 31, 2023 Virginia retail net book values of APCo's Amos and Mountaineer Plants.

In July 2025, APCo filed a request with the Virginia SCC to finance, through the issuance of securitization bonds, approximately $1.4 billion of Virginia jurisdictional undepreciated property balances and a major storm operation and maintenance regulatory asset deferral balance. This proposed securitization included: (a) $1.2 billion of undepreciated Virginia jurisdictional plant balances as of December 31, 2023 for the Amos and Mountaineer Plants and (b) $141 million of Virginia jurisdictional major storm other operation and maintenance expenses deferred during the 2024-2025 biennial period.

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.

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 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. Based on the information currently available, management does not believe a loss is probable and cannot determine a range of potential losses, if any, that is reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP has a substantial capital investment program and incurs additional operational costs to comply with environmental control requirements. Additional investments and operational changes will be made in response to existing and potential future 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 unable to predict changes in regulations, regulatory guidance, legal interpretations, policy positions and implementation actions that may result from the current Presidential administration.

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 June 30, 2025, AEP owned generating capacity of approximately 24,400 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 in 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, (g) policy changes implemented by the Presidential administration and (h) other factors. In 2025, the Federal EPA under the current Presidential administration has proposed to rescind some of those rules and is evaluating potential changes to others.

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 32 states, including Texas. In September 2024, the Federal EPA signed a proposed rule to partially approve and partially disapprove the Texas SIP revision. In May 2025, the Federal EPA proposed to withdraw the prior proposed rule, including the proposed partial disapproval of the Texas SIP revision, and instead has proposed to approve the Texas Regional Haze SIP.

Cross-State Air Pollution Rule

CSAPR is a regional trading program that the Federal EPA began implementing in 2015 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 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. Additionally, in February 2025, the Federal EPA filed a motion with the court seeking to hold the legal challenges related to the Good Neighbor Plan in abeyance for 60 days, to allow the new administration time to review the rule. In March 2025, the Federal EPA filed a motion for the Good Neighbor Plan to remand the rule while leaving it in effect, indicating that the Federal EPA has identified issues with the rule that make reconsideration of issues, including issues raised in the litigation, appropriate. In April 2025, the D.C. Circuit Court of Appeals removed the cases challenging the Good Neighbor Plan from the oral argument calendar and placed the cases in abeyance pending further order of the court, with status reports to be filed at 90-day intervals beginning July 14, 2025. The order further requires the parties to file motions to govern further proceedings within 30 days of the Federal EPA's completion of its review of the rule. Management will continue to monitor this litigation and any further actions by the Federal EPA 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 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 challenges to the rule before the D.C. Circuit Court of Appeals were placed on an expedited schedule, with oral arguments held in December 2024. On February 5, 2025, the Federal EPA filed an unopposed motion asking the court to withhold issuing an opinion and to hold the case in abeyance for 60 days to allow the new Agency leadership to review the underlying rule. The court granted that motion on February 19, 2025 and ordered the parties to file motions to govern further proceedings by April 21, 2025. On April 21, 2025, the Federal EPA filed an unopposed motion to hold the case in abeyance while the Federal EPA conducts a rulemaking to reassess the challenged rule, with status reports due every 90 days. The court has not ruled on that motion. On June 11, 2025, the Federal EPA proposed to determine that GHG emissions from fossil-fueled power plants do not significantly contribute to air pollution that may endanger public health or the environment. This determination would eliminate all GHG standards for existing and new fossil-fuel plants. As an alternative, the Federal EPA proposed to eliminate GHG standards for existing coal and gas units and to keep only certain emission limits applicable to new sources. These proposals have not been finalized. On July 29, 2025, the Federal EPA announced that it would be proposing a repeal of the 2009 Endangerment Finding, which determined that greenhouse gas emissions endanger public health and welfare. The 2009 Endangerment Finding is the basis of Federal EPA's authority to regulate greenhouse gas emissions under the Clean Air Act and was used to first regulate motor vehicle emissions. We are evaluating the Federal EPA's proposed repeal of the 2009 Endangerment Finding and its impact on Federal EPA's authority to regulate greenhouse gas emissions from electric generators. Management cannot predict the outcome of the current litigation or Federal EPA's proposed actions related to the rule or the Endangerment Finding and any subsequent litigation that may result. Excessive costs to comply with environmental regulations have led to the announcement of early plant closures across the country. The Federal EPA's 2024 GHG rules, and suite of other new rules issued simultaneously and 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 those rules remain in place. If AEP is unable to recover the costs of its investments, it would reduce future net income and cash flows and impact financial condition.

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. The litigation is being held in abeyance while the current Presidential administration evaluates the rule. In April 2025, the President issued a Proclamation exempting certain generation sources from the requirement to comply with the 2024 MATS rule for two years beyond the rule's compliance date. In June 2025, the Federal EPA proposed to repeal the 2024 MATS rule and revert to the 2012 MATS rule emission standards. Management does not anticipate any significant challenges complying with the 2024 MATS rule, should the proposed repeal not be finalized.

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. As originally promulgated, the rule applied to active and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers. 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"). In March 2025, the Federal EPA announced plans to make changes to the CCR Rule and to work with states to implement future CCR requirements. See "Federal EPA's Revised CCR Rule" section in Note 5 for additional information.

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 eliminate 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. In October 2024, the court denied the motion. The litigation challenging the ELG Rule is being held in abeyance while the new administration evaluates the rule. In March 2025, the Federal EPA announced plans to reconsider the standards established by the 2024 ELG rule. Management cannot predict the outcome of the litigation or any further actions by the Federal EPA related to the ELG rule.

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 June 30, 2025, 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	$ 79.8	$ 204.7	2026	(c)	$ 16.7
SWEPCo	Pirkey Plant	—	132.6 (d)	2023	(e)	—
SWEPCo	Welsh Plant, Units 1 and 3	300.9	192.7	2028 (f)	(g)	45.9

(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. In April 2025, PSO and ODEQ finalized a second amended regional haze agreement that would allow continued operation of the Northeastern Plant, Unit 3, on natural gas, through May 31, 2041. This agreement is contingent upon approval by the Federal EPA in the form of a revised SIP. ODEQ is in the process of preparing a SIP submission for the Federal EPA's review and approval.
(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 is seeking recovery of the $37 million Arkansas jurisdictional share and a weighted average cost of capital carrying charge in the base rate case filed in March 2025. 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. In December 2024, SWEPCo filed an application for a Certificate of Convenience and Necessity (CCN) with the APSC, LPSC and PUCT to convert Welsh Plant, Units 1 and 3 to natural gas in 2028 and 2027, respectively.
(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 applicable to each public utility subsidiary. 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 (loss) attributable to AEP Common Shareholders for the three months ended and six months ended June 30, 2025 as compared to the three months ended and six months ended June 30, 2024 in accordance with GAAP. For AEP's Vertically Integrated Utilities and Transmission and Distribution Utilities segments and Registrant Subsidiaries 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 six months ended June 30, 2025 and 2024, see the discussions of Results of Operations by Subsidiary Registrant.

A detailed discussion of AEP's 2024 results of operations by operating segment can be found in Management's Discussion and Analysis of Financial Condition and Results of Operation section included in the 2024 Annual Report.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions)			
Vertically Integrated Utilities	$ 432.7	$ 65.7	$ 756.8	$ 626.5
Transmission and Distribution Utilities	223.9	146.8	388.5	297.1
AEP Transmission Holdco	578.4	200.7	813.0	409.4
Generation & Marketing	62.1	(4.8)	164.5	132.8
Corporate and Other	(71.3)	(68.1)	(96.8)	(122.4)
Earnings Attributable to AEP Common Shareholders	$ 1,225.8	$ 340.3	$ 2,026.0	$ 1,343.4

See Note 8 - Business Segments for additional information on Earnings (Loss) Attributable to AEP Common Shareholders by segment.

Heating Degree Days and Cooling Degree Days

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.

The actual heating degree days are calculated on a 55-degree temperature base and the actual cooling degree days are calculated on a 65-degree temperature base for Registrant Subsidiaries except AEP Texas. AEP Texas' actual heating degree days are calculated on a 55-degree temperature base and actual cooling degree days are calculated on a 70-degree temperature base. Due to the recent more volatile weather, effective in January 2025, the calculation methodology for heating degree days and cooling degree days was changed from a daily minimum/maximum average temperature over a thirty-year period to a daily hourly average temperature over a twenty-year period. This change did not have a material impact on the Registrants' discussion of weather-related usage.

VERTICALLY INTEGRATED UTILITIES

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
	(in millions of KWhs)			
Retail:				
Residential	6,372	6,672	15,776	15,232
Commercial	6,297	6,084	12,193	11,853
Industrial	8,595	8,749	16,696	17,001
Miscellaneous	569	568	1,102	1,106
Total Retail	21,833	22,073	45,767	45,192
Wholesale (a)	3,443	3,176	8,234	6,939
Total KWhs	25,276	25,249	54,001	52,131

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

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
	(in degree days)			
Eastern Region				
Actual – Heating	118	81	1,735	1,302
Normal – Heating	133	138	1,700	1,743
Actual – Cooling	374	473	382	474
Normal – Cooling	348	339	352	343
Western Region				
Actual – Heating	21	5	966	743
Normal – Heating	34	33	903	909
Actual – Cooling	772	921	831	976
Normal – Cooling	738	709	771	739

Vertically Integrated Utilities
Reconciliation of 2024 to 2025 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Earnings Attributable to AEP Common Shareholders	$ 65.7	$ 626.5
Changes in Revenues:		
Retail Revenues	286.6	480.9
Off-system Sales	55.9	62.3
Transmission Revenues	62.9	71.9
Other Revenues	(9.2)	(29.0)
Total Change in Revenues	396.2	586.1
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(49.7)	(126.0)
Other Operation and Maintenance	(28.6)	(26.7)
Asset Impairments and Other Related Charges	13.4	13.4
Depreciation and Amortization	(45.1)	(106.7)
Taxes Other Than Income Taxes	10.0	16.1
Other Income	(0.9)	—
Allowance for Equity Funds Used During Construction	3.2	7.9
Non-Service Cost Components of Net Periodic Pension Cost	(3.6)	(11.8)
Interest Expense	(10.8)	(54.3)
Total Change in Expenses and Other	(112.1)	(288.1)
Income Tax Expense	82.7	(168.3)
Equity Earnings of Unconsolidated Subsidiary	—	(0.1)
Net Income Attributable to Noncontrolling Interests	0.2	0.7
2025 Earnings Attributable to AEP Common Shareholders	$ 432.7	$ 756.8

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Retail Revenues** increased $287 million primarily due to the following:
  - A $160 million increase due to a revenue refund provision recorded in 2024 associated with the Turk Plant and SWEPCo’s 2012 Texas Base Rate Case.
  - A $64 million increase in base rate revenues at I&M and PSO.
  - A $40 million increase in weather-normalized revenues primarily in the residential and commercial classes, partially offset by a decrease in the industrial class.
  - A $38 million increase in rider revenues across all companies.
  - A $27 million increase in fuel revenues primarily due to increases at APCo and I&M, partially offset by a decrease at PSO.

  These increases were partially offset by:
  - A $42 million decrease in weather-related usage primarily in the residential class driven by an 18% decrease in cooling degree days.
  - A $22 million decrease due to regulatory provisions for refund at I&M.

- **Off-system Sales** increased $56 million primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales at I&M.
- **Transmission Revenues** increased $63 million primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** decreased $9 million primarily due to revenues from a customer project to enhance transmission resiliency in 2024 at PSO.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** increased $50 million primarily due to an increase at I&M, partially offset by decreases at APCo and PSO.
- **Other Operation and Maintenance** expenses increased $29 million primarily due to the following:
  - A $53 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $22 million increase in distribution expenses primarily due to vegetation management costs.
  - A $17 million increase in PJM and SPP transmission expenses.
  - A $6 million increase in nuclear expenses at Cook Plant.

  These increases were partially offset by:
  - A $76 million decrease in employee-related expenses due to the voluntary severance program that occurred in the second quarter of 2024.
- **Asset Impairments and Other Related Charges** decreased $13 million due to the Federal EPA's revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses increased $45 million primarily due to a higher depreciable base at APCo, I&M and SWEPCo.
- **Taxes Other Than Income Taxes** decreased $10 million primarily due to lower business and occupation taxes at APCo.
- **Interest Expense** increased $11 million primarily due to a prior year deferral of expenses as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking.
- **Income Tax Expense** decreased $83 million primarily due to the following:
  - A $114 million decrease due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $30 million decrease due to an increase in PTCs.

  These decreases were partially offset by:
  - A $60 million increase due to an increase in pretax book income.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Retail Revenues** increased $481 million primarily due to the following:
  - A $160 million increase due to a revenue refund provision recorded in 2024 associated with the Turk Plant and SWEPCo's 2012 Texas Base Rate Case.
  - A $131 million increase in base rate revenues at I&M and PSO.
  - A $110 million increase in rider revenues across all companies.
  - A $60 million increase in fuel revenues primarily due to increases at APCo and I&M, partially offset by a decrease at PSO.
  - A $41 million increase in weather-related usage primarily in the residential class driven by a 32% increase in heating degree days.
  - A $28 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 $71 million decrease due to regulatory provisions for refund at I&M.
- **Off-system Sales** increased $62 million primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales at I&M.
- **Transmission Revenues** increased $72 million primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** decreased $29 million primarily due to revenues from a customer project to enhance transmission resiliency in 2024 at PSO, a decrease in sales of renewable energy credits at APCo and I&M and a decrease in River Transportation Division (RTD) barging revenues at I&M.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $126 million primarily due to increases at I&M and SWEPCo, partially offset by decreases at APCo and PSO.
- **Other Operation and Maintenance** expenses increased $27 million primarily due to the following:
    - A $53 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
    - A $34 million increase in PJM and SPP transmission expenses.
    - A $32 million increase in distribution expenses primarily due to vegetation management costs.

  These increases were partially offset by:
    - A $76 million decrease in employee-related expenses due to the voluntary severance program that occurred in the second quarter of 2024.
    - A $14 million decrease to a disallowance recorded at SWEPCo 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** decreased $13 million due to the Federal EPA's revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses increased $107 million primarily due to the following:
    - A $65 million increase primarily due to a higher depreciable base at APCo, I&M and SWEPCo.
    - A $9 million increase due to a prior year deferral of Excess ADIT as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs at I&M.
    - An $8 million increase at SWEPCo due to the amortization of the Storm Recovery Funding securitized assets.
    - A $5 million increase in regulatory reserves related to Nuclear PTCs at I&M.
- **Taxes Other Than Income Taxes** decreased $16 million primarily due to lower business and occupation taxes at APCo.
- **Allowance for Equity Funds Used During Construction** increased $8 million primarily due to higher CWIP.
- **Non-Service Cost Components of Net Periodic Benefit Cost** increased $12 million primarily due to an increase in loss amortization and discount rates from 2024 to 2025.
- **Interest Expense** increased $54 million primarily due to a prior year deferral of expenses as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking.
- **Income Tax Expense** increased $168 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 in retail ratemaking recorded in 2024.
    - A $57 million increase due to an increase in pretax book income.
    - 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 recorded in 2024.

  These increases were partially offset by:
    - A $114 million decrease due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
    - A $32 million decrease due to an increase in PTCs.

TRANSMISSION AND DISTRIBUTION UTILITIES

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions of KWhs)			
Retail:				
Residential	6,299	6,593	13,310	12,873
Commercial	11,042	9,209	20,630	17,200
Industrial	7,048	6,826	13,804	13,638
Miscellaneous	172	180	344	360
Total Retail (a)	24,561	22,808	48,088	44,071
Wholesale (b)	464	253	1,131	843
Total KWhs	25,025	23,061	49,219	44,914

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in degree days)			
Eastern Region				
Actual – Heating	170	110	2,077	1,573
Normal – Heating	173	181	1,993	2,052
Actual – Cooling	336	422	342	422
Normal – Cooling	323	306	325	309
Western Region				
Actual – Heating	4	1	296	162
Normal – Heating	4	3	208	198
Actual – Cooling	992	1,198	1,153	1,344
Normal – Cooling	909	949	1,021	1,086

Transmission and Distribution Utilities
Reconciliation of 2024 to 2025 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Earnings Attributable to AEP Common Shareholders	$ 146.8	$ 297.1
Changes in Revenues:		
Retail Revenues	38.2	64.4
Off-system Sales	12.9	25.8
Transmission Revenues	(6.2)	14.2
Other Revenues	(30.6)	(53.8)
Total Change in Revenues	14.3	50.6
Changes in Expenses and Other:		
Purchased Electricity for Resale	(3.9)	7.9
Purchased Electricity from AEP Affiliates	10.7	41.4
Other Operation and Maintenance	(20.4)	(78.3)
Asset Impairments and Other Related Charges	52.9	52.9
Depreciation and Amortization	25.4	45.0
Taxes Other Than Income Taxes	18.7	4.3
Other Income	(2.6)	(2.0)
Allowance for Equity Funds Used During Construction	(0.2)	4.2
Non-Service Cost Components of Net Periodic Benefit Cost	1.1	0.6
Interest Expense	(4.2)	(19.6)
Total Change in Expenses and Other	77.5	56.4
Income Tax Expense	(15.5)	(17.8)
Equity Earnings (Loss) of Unconsolidated Subsidiary	0.8	2.2
2025 Earnings Attributable to AEP Common Shareholders	$ 223.9	$ 388.5

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Retail Revenues** increased $38 million primarily due to the following:
  - A $43 million increase in base case and rider revenues.
  - A $24 million increase in weather-normalized revenues primarily in the commercial and industrial classes in Ohio.

  These increases were partially offset by:
  - An $11 million decrease due to lower prices and lower customer participation in OPCo's SSO.
  - A $9 million decrease in weather-related usage driven by a 20% decrease in cooling degree days in the Eastern Region and a 17% decrease in cooling degree days in the Western Region.
  - A $7 million decrease in weather-normalized revenues primarily in the residential class in Texas.
- **Off-system Sales** increased $13 million primarily due to increased sales of OVEC purchased power driven by higher market prices and volume.
- **Transmission Revenues** decreased $6 million primarily due to the following:
  - A $35 million decrease due to lower peak loads included in the 2025 billing rates in Texas.

  This decrease was partially offset by:
  - A $25 million increase in interim rates driven by increased transmission investments in Texas.

- **Other Revenues** decreased $31 million primarily due to the maturity of Transition Funding III LLC securitization bonds in December 2024 and third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.

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

- **Purchased Electricity from AEP Affiliates** expenses decreased $11 million primarily due to decreased recoverable purchases to serve SSO customers in Ohio.
- **Other Operation and Maintenance** expenses increased $20 million primarily due to the following:
  - A $29 million increase in recoverable transmission expenses in Texas.
  - A $16 million increase for transmission and distribution related expenses in Texas.
  - An $8 million increase in transmission expenses in Ohio primarily due to an increase in recoverable PJM expenses.
  - An $8 million increase in distribution expenses in Ohio primarily related to recoverable storm restoration costs and recoverable vegetation management expenses.

  These increases were partially offset by:
  - A $33 million decrease in employee-related expenses due to the voluntary severance program that occurred in the second quarter of 2024.
  - A $9 million decrease related to recoverable energy assistance program expenses for qualified Ohio customers.
- **Asset Impairments and Other Related Charges** decreased $53 million primarily due to the Federal EPA revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses decreased $25 million primarily due to the following:
  - A $16 million decrease in the amortization of securitized transition assets due to the maturity of Transition Funding III LLC securitization bonds in December 2024.
  - An $11 million decrease due to the deferral of eligible costs related to HB 5247.
  - A $7 million decrease due to capital rider under-recoveries in Ohio.

  These decreases were partially offset by:
  - A $9 million increase due to a higher depreciable base in Texas.
- **Taxes Other Than Income Taxes** decreased $19 million primarily due to the following:
  - A $12 million decrease due to lower property taxes in Ohio.
  - A $6 million decrease in state excise taxes in Ohio due to decreased billed KWhs in 2025.
- **Interest Expense** increased $4 million primarily due to the following:
  - An $8 million increase due to higher debt balances and interest rates in Texas.
  - A $5 million increase due to a decrease of capitalization of AFUDC on prepaid pension and OPEB in Texas.

  These increases were partially offset by:
  - A $12 million decrease due to the deferral of eligible costs related to HB 5247.
- **Income Tax Expense** increased $16 million primarily due to the following:
  - A $19 million increase due to an increase in pretax book income.

  This increase was partially offset by:
  - A $5 million decrease due to an increase in amortization of Excess ADIT.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Retail Revenues** increased $64 million primarily due to the following:
  - A $133 million increase in base case and rider revenues.
  - A $34 million increase in weather-related usage driven by a 32% increase in heating degree days in the Eastern Region and an 83% increase in heating degree days in the Western Region.

  These increases were partially offset by:
  - An $88 million decrease due to lower prices and lower customer participation in OPCo’s SSO.
  - An $10 million decrease in weather-normalized revenues primarily in the residential class in Texas and Ohio partially offset by an increase in the commercial class in Ohio.
- **Off-system Sales** increased $26 million primarily due to increased sales of OVEC purchased power driven by higher market prices and volume.
- **Transmission Revenues** increased $14 million primarily due to the following:
  - A $42 million increase in interim rates driven by increased transmission investments in Texas.
  - A $6 million increase in Ohio primarily due to continued transmission investment.

  These increases were partially offset by:
  - A $34 million decrease due to lower peak loads included in the 2025 billing rates in Texas.

- **Other Revenues** decreased $54 million primarily due to the following:
  - A $42 million decrease in Texas primarily due to the maturity of Transition Funding III LLC securitization bonds in December 2024.
  - A $7 million decrease in recoverable sales of renewable energy credits in Ohio.
  - A $5 million decrease due to third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.

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

- **Purchased Electricity for Resale** expenses decreased $8 million primarily due to the following:
  - A $41 million decrease in recoverable auction purchases primarily due to lower prices in Ohio.
  - A $12 million decrease in recoverable alternative energy rider expenses in Ohio.

  These decreases were partially offset by:
  - A $30 million estimated reduction in regulatory assets for OVEC-related purchased power costs that are no longer probable of future recovery due to recently approved legislation in Ohio.
  - A $17 million increase in recoverable OVEC costs.
- **Purchased Electricity from AEP Affiliates** expenses decreased $41 million primarily due to decreased recoverable purchases to serve SSO customers in Ohio.
- **Other Operation and Maintenance** expenses increased $78 million primarily due to the following:
  - A $58 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - A $42 million increase in recoverable transmission expenses in Texas.
  - An $18 million increase in transmission and distribution related expenses in Texas.
  - A $7 million increase in property and liability insurance expenses in Texas.

  These increases were partially offset by:
  - A $32 million decrease in employee-related expenses due to the voluntary severance program that occurred in the second quarter of 2024.
  - A $19 million decrease related to recoverable energy assistance program expenses for qualified Ohio customers.
- **Asset Impairments and Other Related Charges** decreased $53 million due to the Federal EPA's Revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses decrease $45 million due to the following:
  - A $32 million decrease in the amortization of securitized transition assets due to the maturity of Transition Funding III LLC securitization bonds in December 2024.
  - A $19 million decrease primarily due to capital rider under-recoveries in Ohio.
  - An $11 million decrease due to the deferral of eligible costs related to HB 5247.

  These decreases were partially offset by:
  - A $19 million increase due to a higher depreciable base in Texas.
- **Interest Expense** increased $20 million primarily due to:
  - A $26 million increase due to higher debt balances in Ohio and higher debt balances and interest rates in Texas.
  - A $5 million increase due to a decrease of capitalization of AFUDC on prepaid pension and OPEB in Texas.

  These increases were partially offset by:
  - A $12 million decrease due to the deferral of eligible costs related to HB 5247.
- **Income Tax Expense** increased $18 million due to:
  - A $23 million increase due to an increase in pretax book income.

  This increase was partially offset by:
  - A $7 million decrease due to an increase in amortization of Excess ADIT.

AEP TRANSMISSION HOLDCO

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	June 30, 2025	June 30, 2024
	(in millions)	
Plant in Service	$ 16,495.8	$ 15,013.1
Construction Work in Progress	2,371.2	2,115.8
Accumulated Depreciation and Amortization	1,810.0	1,481.4
Total Transmission Property, Net	$ 17,057.0	$ 15,647.5

AEP Transmission Holdco
Reconciliation of 2024 to 2025 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Earnings Attributable to AEP Common Shareholders	$ 200.7	$ 409.4
Changes in Transmission Revenues:		
Transmission Revenues	266.7	311.5
Total Change in Transmission Revenues	266.7	311.5
Changes in Expenses and Other:		
Other Operation and Maintenance	0.7	0.4
Depreciation and Amortization	(12.2)	(20.3)
Taxes Other Than Income Taxes	—	(0.6)
Interest and Investment Income	(2.6)	(4.4)
Allowance for Equity Funds Used During Construction	(1.1)	3.5
Non-Service Cost Components of Net Periodic Pension Cost	0.2	(0.5)
Interest Expense	(5.4)	(5.4)
Total Change in Expenses and Other	(20.4)	(27.3)
Income Tax Expense	196.3	183.7
Equity Earnings of Unconsolidated Subsidiary	(4.4)	(3.9)
Net Income Attributable to Noncontrolling Interests	(60.5)	(60.4)
2025 Earnings Attributable to AEP Common Shareholders	$ 578.4	$ 813.0

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Transmission Revenues** increased $267 million primarily due to the following:
  - A $214 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $50 million increase due to continued transmission investment.

Expenses and Other, Income Tax Expense and Net Income Attributable to Noncontrolling Interests changed between years as follows:

- **Depreciation and Amortization** expenses increased $12 million primarily due to a higher depreciable base.
- **Interest Expense** increased $5 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** decreased $196 million primarily due to the following:
  - A $254 million decrease due to a reduction in Excess ADIT as a result of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $51 million increase due to an increase in pretax book income.
  - A $7 million increase due to an increase in state taxes.
- **Net Income Attributable to Noncontrolling Interests** increased $61 million primarily due to the Midwest Transmission noncontrolling interest transaction that closed in June 2025.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Transmission Revenues** increased $312 million primarily due to the following:
  - A $214 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $97 million increase due to continued transmission investment.

Expenses and Other, Income Tax Expense and Net Income Attributable to Noncontrolling Interests changed between years as follows:

- **Depreciation and Amortization** expenses increased $20 million due to a higher depreciable base.
- **Interest Expense** increased $5 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** decreased $184 million primarily due to the following:
  - A $254 million decrease due to a reduction in Excess ADIT as a result of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $59 million increase due to an increase in pretax book income.
  - An $8 million increase due to an increase in state taxes.
- **Net Income Attributable to Noncontrolling Interests** increased $60 million primarily due to the Midwest Transmission noncontrolling interest transaction that closed in June 2025.

GENERATION & MARKETING

Reconciliation of 2024 to 2025 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Earnings (Loss) Attributable to AEP Common Shareholders	$ (4.8)	$ 132.8
Changes in Revenues:		
Merchant Generation	15.9	39.3
Renewable Generation	(8.8)	(15.6)
Retail, Trading and Marketing	91.6	258.4
Total Change in Revenues	98.7	282.1
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(128.6)	(338.5)
Other Operation and Maintenance	42.7	43.8
Asset Impairments and Other Related Charges	76.2	76.2
Depreciation and Amortization	0.8	4.9
Taxes Other Than Income Taxes	0.2	(0.3)
Interest and Investment Income	(1.0)	(6.0)
Non-Service Cost Components of Net Periodic Benefit Cost	(0.5)	(0.9)
Interest Expense	2.9	7.0
Total Change in Expenses and Other	(7.3)	(213.8)
Income Tax Expense	(24.5)	(35.7)
Equity Earnings of Unconsolidated Subsidiaries	—	(0.9)
2025 Earnings Attributable to AEP Common Shareholders	$ 62.1	$ 164.5

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Merchant Generation** increased $16 million primarily due to higher realized prices in 2025.
- **Renewable Generation** decreased $9 million primarily due to the sale of Onsite Partners in September 2024.
- **Retail, Trading and Marketing** increased $92 million primarily due to higher MTM hedging activity and higher market prices in 2025.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $129 million primarily due to an increase in energy costs in 2025.
- **Other Operation and Maintenance** expenses decreased $43 million primarily due to renewable contract termination proceeds in 2025 and the sale of Onsite Partners in September 2024.
- **Asset Impairments and Other Related Charges** decreased $76 million due to the Federal EPA's revised CCR rules finalized in 2024.
- **Income Tax Expense** increased $25 million primarily due to the following:
  - A $19 million increase due to an increase in pretax book income.
  - A $2 million increase due to a decrease in the amortization of deferred ITCs.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Merchant Generation** increased $39 million primarily due to higher realized prices in 2025.
- **Renewable Generation** decreased $16 million primarily due to the sale of Onsite Partners in September 2024.
- **Retail, Trading and Marketing** increased $258 million primarily due to higher MTM hedging activity and higher market prices in 2025.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $339 million primarily due to an increase in energy costs in 2025.
- **Other Operation and Maintenance** expenses decreased $44 million primarily due to renewable contract termination proceeds in 2025 and the sale of Onsite Partners in September 2024.
- **Asset Impairments and Other Related Charges** decreased $76 million due to the Federal EPA's revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses decreased $5 million primarily due to the sale of Onsite Partners in September 2024.
- **Interest and Investment Income** decreased $6 million primarily due to the sale of Onsite Partners in September 2024.
- **Interest Expense** decreased $7 million due to lower advances from affiliates.
- **Income Tax Expense** increased $36 million primarily due to:
  - A $16 million increase due to a decrease in amortization of deferred ITCs primarily from the sale of NMRD in 2024.
  - A $14 million increase due to an increase in pretax book income.

CORPORATE AND OTHER

Second Quarter of 2025 Compared to Second Quarter of 2024

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $68 million in 2024 to a loss of $71 million in 2025 primarily due to:

- A $10 million decrease due to the cessation of AEP T&D Services substation construction contracts.
- A $6 million decrease at EIS primarily due to increased insurance reserves.
- A $5 million decrease in interest income primarily due to lower advances to affiliates.

These decreases in earnings were partially offset by:

- A $19 million increase in Income Tax Benefit primarily due to the following:
  - A $9 million increase due to a decrease in state taxes.
  - A $5 million increase due to a decrease in pretax book income.
  - A $4 million increase due to an increase in deferred ITC amortization and PTCs.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

Earnings Attributable to AEP Common Shareholders from Corporate and Other increased from a loss of $122 million in 2024 to a loss of $97 million in 2025 primarily due to:

- A $28 million increase in Income Tax Benefit primarily due to the following:
  - A $17 million increase due to an increase in deferred ITC amortization and PTCs.
  - An $11 million increase due to a decrease in state taxes.
- A $13 million decrease in interest expense due to lower interest rates.
- A $12 million increase in equity earnings.
- An $11 million increase due to the recognition of deferred revenues for completed agreements.

These increases in earnings were partially offset by:

- A $23 million decrease at EIS primarily due to increased insurance reserves.
- A $16 million decrease in interest income primarily due to lower advances to affiliates.

AEP CONSOLIDATED INCOME TAXES

Second Quarter of 2025 Compared to Second Quarter of 2024

Income Tax Benefit increased $258 million primarily due to:

- A $368 million increase due to a reduction in Excess ADIT as a result of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- A $32 million increase due to an increase in deferred ITC amortization and PTCs.

These increases in Income Tax Benefit were partially offset by:

- A $145 million decrease due to an increase in pretax book income.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

Income Tax Benefit decreased $10 million primarily due to:

- A $212 million 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 ratemaking recorded in 2024.
- A $158 million decrease due to an increase in pretax book income.
- A $32 million 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 recorded in 2024.
- A $15 million decrease due to a decrease in amortization of Excess ADIT.

These decreases in Income Tax Benefit were partially offset by:

- A $368 million increase due to a reduction in Excess ADIT as a result of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- A $33 million increase due to an increase in deferred ITC amortization and PTCs.

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

	June 30, 2025		December 31, 2024	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 44,525.5	57.8 %	$ 42,642.8	59.1 %
Short-term Debt	1,501.6	2.0	2,523.8	3.5
Total Debt	46,027.1	59.8	45,166.6	62.6
AEP Common Equity	29,871.1	38.8	26,943.8	37.3
Noncontrolling Interests	1,097.3	1.4	42.3	0.1
Total Debt and Equity Capitalization	$ 76,995.5	100.0 %	$ 72,152.7	100.0 %

AEP's ratio of debt-to-total capital decreased from 62.6% to 59.8% as of December 31, 2024 and June 30, 2025, respectively, primarily due to an increase in earnings and the Midwest Transmission Holdings Noncontrolling Interest transaction, partially offset by an increase in long-term debt to support our capital investment plan 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 for the next twelve months and foreseeable future. As of June 30, 2025, 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, including the settlement of the March 2025 forward sale of equity, which is expected to occur on or prior to December 31, 2026. 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 six months ended June 30, 2025.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of June 30, 2025, available liquidity was approximately $5.6 billion as illustrated in the table below:

	Amount	Maturity
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	227.3	
Total Liquidity Sources	6,227.3	
Less: AEP Commercial Paper Outstanding	600.0	
Net Available Liquidity	$ 5,627.3	

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. The maximum amount of commercial paper outstanding during the first six months of 2025 was $2.9 billion. The weighted-average interest rate for AEP's commercial paper for the six months ended June 30, 2025 was 4.64%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of June 30, 2025 was $361 million with maturities ranging from July 2025 to July 2026.

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 June 30, 2025, the affiliated utility subsidiaries were in compliance with all requirements under the agreement.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreement excludes securitization bonds and debt of AEP Credit. As of June 30, 2025, this contractually-defined percentage was 56.6%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $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.

March 2025 Forward Sale of Equity

See "Forward Sale of Equity" section of Note 13 for additional information regarding AEP's forward sale of 22,549,020 shares of common stock in March 2025.

ATM Program

In 2024, approximately $0.4 billion of common stock was offered and sold under the ATM program. There were no issuances under the ATM program for the six months ended June 30, 2025. Approximately $1.3 billion of equity is available for issuance under the ATM program upon the filing of a prospectus supplement.

Dividend Policy and Restrictions

The Board of Directors of AEP (AEP Board) declared a quarterly dividend of $0.93 per share in July 2025. Future dividends are at the discretion of the AEP Board and 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 13 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 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.

	Six Months Ended June 30,	
	2025	2024
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 246.0	$ 379.0
Net Cash Flows from Operating Activities	2,671.1	2,904.2
Net Cash Flows Used for Investing Activities	(5,347.3)	(3,249.7)
Net Cash Flows from Financing Activities	2,708.8	214.4
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	32.6	(131.1)
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 278.6	$ 247.9

Operating Activities

	Six Months Ended June 30,	
	2025	2024
	(in millions)	
Net Income	$ 2,090.5	$ 1,348.2
Non-Cash Adjustments to Net Income (a)	1,518.5	1,596.6
Mark-to-Market of Risk Management Contracts	(240.6)	(75.0)
Pension Contributions to Qualified Plan Trust	(94.7)	—
Property Taxes	240.6	213.2
Deferred Fuel Over/Under-Recovery, Net	(41.3)	120.0
Change in Other Noncurrent Assets	(439.5)	(131.0)
Change in Other Noncurrent Liabilities	41.4	189.9
Change in Certain Components of Working Capital	(403.8)	(357.7)
Net Cash Flows from Operating Activities	$ 2,671.1	$ 2,904.2

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Deferred Income Taxes, Asset Impairments and Other Related Charges and AFUDC.

Net Cash Flows from Operating Activities decreased by $233 million primarily due to the following:

- A $457 million decrease in cash from Change in Other Noncurrent Assets and Change in Other Noncurrent Liabilities. This decrease is primarily due to changes in regulatory assets and liabilities driven by timing differences in collections from and refunds to customers under rate rider mechanisms.
- A $166 million decrease in cash due to changes in risk management contract collateral positions.
- A $161 million decrease in cash primarily due to the timing of fuel and purchase power related revenues and expenses.
- A $95 million decrease in cash due to a discretionary contribution to the qualified pension plan. See Note 7 - Benefit Plans for additional information.

These decreases in cash were partially offset by:

- A $664 million increase in cash from Net Income, after non-cash adjustments. See "Results of Operations" for further detail.

Investing Activities

	Six Months Ended June 30,	
	2025	2024
	(in millions)	
Construction Expenditures	$ (4,020.2)	$ (3,318.3)
Acquisitions of Generation Facilities	(1,359.3)	—
Acquisitions of Nuclear Fuel	(45.6)	(69.8)
Proceeds from Sale of Equity Method Investment	—	114.0
Other	77.8	24.4
Net Cash Flows Used for Investing Activities	$ (5,347.3)	$ (3,249.7)

Net Cash Flows Used for Investing Activities increased by $2.1 billion primarily due to the following:

- A $1.4 billion increase due to the acquisitions of Green Country Power Plant, Pixley Solar Energy Facility and Flat Ridge IV Wind Energy Facility. See “Acquisitions” section of Note 6 for additional information.
- A $702 million increase in Construction Expenditures primarily due to increases in Vertically Integrated Utilities of $313 million, Transmission and Distribution Utilities of $247 million and AEP Transmission Holdco of $119 million.
- A $114 million decrease in Proceeds from Sale of Equity Method Investment. See “Disposition of NMRD” section of Note 6 for additional information.

Financing Activities

	Six Months Ended June 30,	
	2025	2024
	(in millions)	
Issuance of Common Stock	$ 131.8	$ 475.8
Issuance/Retirement of Debt, Net	816.9	745.7
Principal Payments for Finance Lease Obligations	(25.0)	(35.8)
Proceeds from the Midwest Transmission Holdings Noncontrolling Interest Transaction, Net of Transaction Costs	2,782.9	—
Dividends Paid on Common Stock	(1,000.5)	(936.0)
Other	2.7	(35.3)
Net Cash Flows from Financing Activities	$ 2,708.8	$ 214.4

Net Cash Flows from Financing Activities increased by $2.5 billion primarily due to the following:

- A $2.8 billion increase due to proceeds from the Midwest Transmission Holdings Noncontrolling Interest transaction. See “Noncontrolling Interest in OHTCo and IMTCo” section of Note 6 for additional information.
- A $445 million decrease in retirements of long-term debt. See Note 13 - Financing Activities for additional information.

These increases in cash were partially offset by:

- A $500 million decrease in issuances of long-term debt. See Note 13 - Financing Activities for additional information.
- A $344 million decrease in issuances of common stock primarily under AEP’s ATM Program. See Note 13 - Financing Activities for additional information.

See the “Long-term Debt Subsequent Events” section of Note 13 for Long-term debt and other securities issued, retired and principal payments made after June 30, 2025 through July 30, 2025, the date that the second quarter Form 10-Q was filed.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $11.5 billion of capital expenditures in 2025. For the four-year period, 2026 through 2029, management forecasts capital expenditures of $42.9 billion. Management's forecasted capital expenditures 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.

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 has funded, or 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. For more information of forecasted capital expenditures, see the "Budgeted Capital Expenditures" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2024 Annual Report.

SIGNIFICANT CASH REQUIREMENTS

A summary of significant cash requirements is included in the 2024 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 2024 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, asset retirement obligations and the impact of new accounting standards and SEC rulemaking activity.

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 AEP Board. 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, Executive Vice President and Chief Commercial Officer, Senior Vice President and Treasurer, and Senior Vice President of Regulated Commercial Operations. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer, Executive Vice President and Chief Commercial Officer, Senior Vice President and Treasurer, 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, 2024:

MTM Derivative Contract Net Assets (Liabilities)

Six Months Ended June 30, 2025

	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, 2024	$ 91.8	$ (48.0)	$ 161.8	$ 205.6
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(72.0)	(1.1)	(17.0)	(90.1)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	10.7	10.7
Changes in Fair Value Due to Market Fluctuations During the Period (b)	(20.5)	—	50.0	29.5
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	285.1	1.1	—	286.2
Total MTM Risk Management Contracts - Commodity Net Assets (Liabilities) as of June 30, 2025	$ 284.4	$ (48.0)	$ 205.5	441.9
Commodity Cash Flow Hedge Contracts				115.9
Fair Value Hedge Contracts				(47.9)
Collateral Deposits				(79.4)
Total MTM Derivative Contract Net Assets as of June 30, 2025				$ 430.5

(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 June 30, 2025, credit exposure net of collateral to sub investment grade counterparties was approximately 6.2%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss).

As of June 30, 2025, 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	$ 642.8	$ 94.9	$ 547.9	3	$ 351.1
Non-investment Grade	3.5	—	3.5	2	3.5
No External Ratings:					
Internal Investment Grade	18.4	—	18.4	3	13.4
Internal Non-investment Grade	104.4	70.5	33.9	2	27.8
Total as of June 30, 2025	$ 769.1	$ 165.4	$ 603.7		

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

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

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of June 30, 2025, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

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

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

VaR Model
Trading Portfolio

Six Months Ended June 30, 2025				Twelve Months Ended December 31, 2024			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.1	$ 0.7	$ 0.2	$ 0.1	$ 0.2	$ 1.7	$ 0.3	$ 0.1

VaR Model
Non-Trading Portfolio

Six Months Ended June 30, 2025				Twelve Months Ended December 31, 2024			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 6.2	$ 28.8	$ 12.6	$ 4.6	$ 37.9	$ 98.6	$ 19.3	$ 7.6

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 total cumulative increase of 5.25%. In light of the progress on inflation and the balance of risks, during 2024, the Federal Reserve authorized three rate decreases for a total cumulative decrease of 1.0%. 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 on interest rates. For the six months ended June 30, 2025 and 2024, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $34 million and $25 million, respectively.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
REVENUES				
Vertically Integrated Utilities	$ 2,934.5	$ 2,572.0	$ 6,020.0	$ 5,473.2
Transmission and Distribution Utilities	1,442.6	1,428.8	2,958.1	2,912.0
Generation & Marketing	551.0	442.5	1,281.6	958.4
Other Revenues	158.8	135.9	290.6	261.3
TOTAL REVENUES	5,086.9	4,579.2	10,550.3	9,604.9
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,541.4	1,368.5	3,394.3	2,944.3
Other Operation	537.6	817.3	1,290.0	1,579.6
Maintenance	390.7	351.5	709.2	669.0
Asset Impairments and Other Related Charges	—	142.5	—	142.5
Depreciation and Amortization	853.1	821.9	1,686.5	1,609.0
Taxes Other Than Income Taxes	365.0	393.6	787.0	804.0
TOTAL EXPENSES	3,687.8	3,895.3	7,867.0	7,748.4
OPERATING INCOME	1,399.1	683.9	2,683.3	1,856.5
Other Income (Expense):				
Other Income	15.5	13.1	23.3	26.7
Allowance for Equity Funds Used During Construction	57.1	55.2	114.4	98.8
Non-Service Cost Components of Net Periodic Benefit Cost	34.6	37.4	69.7	82.5
Interest Expense	(489.5)	(465.6)	(984.4)	(901.2)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	1,016.8	324.0	1,906.3	1,163.3
Income Tax Expense (Benefit)	(250.9)	6.7	(125.4)	(135.2)
Equity Earnings of Unconsolidated Subsidiaries	20.6	25.2	58.8	49.7
NET INCOME	1,288.3	342.5	2,090.5	1,348.2
Net Income Attributable to Noncontrolling Interests	62.5	2.2	64.5	4.8
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,225.8	$ 340.3	$ 2,026.0	$ 1,343.4
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	534,283,554	528,898,816	533,839,985	527,725,426
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.29	$ 0.64	$ 3.80	$ 2.55
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	536,425,635	530,140,990	535,547,029	528,868,693
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.29	$ 0.64	$ 3.78	$ 2.54

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	**2024**	**2025**	**2024**
Net Income	$ 1,288.3	$ 342.5	$ 2,090.5	$ 1,348.2
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(8.8) and $5.9 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $(2.7) and $4.3 for the Six Months Ended June 30, 2025 and 2024, Respectively	(33.2)	22.4	(10.1)	16.2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $0.1 and $(0.2) for the Six Months Ended June 30, 2025 and 2024, Respectively	0.3	(0.1)	0.6	(0.7)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(32.9)	22.3	(9.5)	15.5
TOTAL COMPREHENSIVE INCOME	1,255.4	364.8	2,081.0	1,363.7
Total Comprehensive Income Attributable To Noncontrolling Interests	62.5	2.2	64.5	4.8
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,192.9	$ 362.6	$ 2,016.5	$ 1,358.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2025 and 2024
(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, 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) (a)		(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) (a)		(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
TOTAL EQUITY – DECEMBER 31, 2024	534.1	$ 3,471.6	$ 9,606.1	$ 13,869.2	$ (3.1)	$ 42.3	$ 26,986.1
Issuance of Common Stock	1.1	7.1	68.3				75.4
Common Stock Dividends				(500.0) (b)		(1.0)	(501.0)
Other Changes in Equity			(22.1)				(22.1)
Net Income				800.2		2.0	802.2
Other Comprehensive Income					23.4		23.4
TOTAL EQUITY – MARCH 31, 2025	535.2	3,478.7	9,652.3	14,169.4	20.3	43.3	27,364.0
Issuance of Common Stock	0.6	3.7	52.7				56.4
Common Stock Dividends				(498.5) (b)		(1.0)	(499.5)
Other Changes in Equity			9.1			0.1	9.2
Midwest Transmission Holdings Noncontrolling Interest Transaction			1,790.5			992.4	2,782.9
Net Income				1,225.8		62.5	1,288.3
Other Comprehensive Loss					(32.9)		(32.9)
TOTAL EQUITY – JUNE 30, 2025	535.8	$ 3,482.4	$ 11,504.6	$ 14,896.7	$ (12.6)	$ 1,097.3	$ 30,968.4

(a) Cash dividends declared per AEP common share were $0.88.
(b) Cash dividends declared per AEP common share were $0.93.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2025 and December 31, 2024
(in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 227.3	$ 202.9
Restricted Cash (June 30, 2025 and December 31, 2024 Amounts Include $51.3 and $43.1, Respectively, Related to Transition Funding, Restoration Funding and Appalachian Consumer Rate Relief Funding, Storm Recovery Funding and Cost Recovery Funding)	51.3	43.1
Other Temporary Investments (June 30, 2025 and December 31, 2024 Amounts Include $197.9 and $206.7, Respectively, Related to EIS)	212.0	215.4
Accounts Receivable:		
Customers	1,134.6	1,100.1
Accrued Unbilled Revenues	393.7	367.0
Pledged Accounts Receivable – AEP Credit	1,279.0	1,161.5
Miscellaneous	53.4	64.1
Allowance for Credit Losses	(63.6)	(60.8)
Total Accounts Receivable	2,797.1	2,631.9
Fuel	616.9	748.9
Materials and Supplies	1,005.1	966.2
Risk Management Assets	469.3	210.4
Accrued Tax Benefits	111.6	38.2
Regulatory Asset for Under-Recovered Fuel Costs	547.4	445.9
Prepayments and Other Current Assets	283.9	285.9
TOTAL CURRENT ASSETS	6,321.9	5,788.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	26,039.7	24,829.7
Transmission	40,304.3	38,871.9
Distribution	32,125.2	31,061.9
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	8,378.2	7,491.6
Construction Work in Progress	6,945.3	6,346.9
Total Property, Plant and Equipment	113,792.7	108,602.0
Accumulated Depreciation and Amortization	27,455.6	26,186.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	86,337.1	82,415.6
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,870.2	5,129.2
Securitized Assets	973.1	554.3
Spent Nuclear Fuel and Decommissioning Trusts	4,609.7	4,395.1
Goodwill	52.5	52.5
Long-term Risk Management Assets	258.9	289.1
Operating Lease Assets	580.6	580.1
Deferred Charges and Other Noncurrent Assets	3,774.5	3,873.3
TOTAL OTHER NONCURRENT ASSETS	15,119.5	14,873.6
TOTAL ASSETS	$ 107,778.5	$ 103,078.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2025 and December 31, 2024
(in millions, except per-share and share amounts)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT LIABILITIES		
Accounts Payable	$ 2,714.2	$ 2,637.6
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	900.0	900.0
Other Short-term Debt	601.6	1,623.8
Total Short-term Debt	1,501.6	2,523.8
Long-term Debt Due Within One Year (June 30, 2025 and December 31, 2024 Amounts Include $181.9 and $216.5, Respectively, Related to DCC Fuel, Restoration Funding, Appalachian Consumer Rate Relief Funding, Storm Recovery Funding, Transource Energy and Cost Recovery Funding)	3,212.4	3,335.0
Risk Management Liabilities	106.1	100.0
Customer Deposits	454.3	454.7
Accrued Taxes	1,527.8	1,922.1
Accrued Interest	479.2	453.3
Obligations Under Operating Leases	91.0	91.9
Other Current Liabilities	1,356.7	1,490.9
TOTAL CURRENT LIABILITIES	11,443.3	13,009.3
NONCURRENT LIABILITIES		
Long-term Debt (June 30, 2025 and December 31, 2024 Amounts Include $1,354.4 and $826.5, Respectively, Related to DCC Fuel, Restoration Funding, Appalachian Consumer Rate Relief Funding, Storm Recovery Funding, Transource Energy and Cost Recovery Funding)	41,313.1	39,307.8
Long-term Risk Management Liabilities	191.6	224.4
Deferred Income Taxes	10,521.7	9,972.4
Regulatory Liabilities and Deferred Investment Tax Credits	7,973.9	8,344.0
Asset Retirement Obligations	3,625.1	3,530.6
Employee Benefits and Pension Obligations	270.5	360.7
Obligations Under Operating Leases	506.5	504.3
Deferred Credits and Other Noncurrent Liabilities	913.8	800.6
TOTAL NONCURRENT LIABILITIES	65,316.2	63,044.8
TOTAL LIABILITIES	76,759.5	76,054.1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEZZANINE EQUITY		
Contingently Redeemable Performance Share Awards	50.6	37.8
TOTAL MEZZANINE EQUITY	50.6	37.8
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2025	2024
Shares Authorized	600,000,000	600,000,000
Shares Issued	535,755,643	534,094,530

	June 30, 2025	December 31, 2024
(1,186,815 Shares were Held in Treasury as of June 30, 2025 and December 31, 2024, Respectively)	3,482.4	3,471.6
Paid-in Capital	11,504.6	9,606.1
Retained Earnings	14,896.7	13,869.2
Accumulated Other Comprehensive Income (Loss)	(12.6)	(3.1)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	29,871.1	26,943.8
Noncontrolling Interests	1,097.3	42.3
TOTAL EQUITY	30,968.4	26,986.1
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY	$ 107,778.5	$ 103,078.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
OPERATING ACTIVITIES		
Net Income	$ 2,090.5	$ 1,348.2
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,686.5	1,609.0
Deferred Income Taxes	(53.6)	(56.1)
Asset Impairments and Other Related Charges	—	142.5
Allowance for Equity Funds Used During Construction	(114.4)	(98.8)
Mark-to-Market of Risk Management Contracts	(240.6)	(75.0)
Pension Contributions to Qualified Plan Trust	(94.7)	—
Property Taxes	240.6	213.2
Deferred Fuel Over/Under-Recovery, Net	(41.3)	120.0
Change in Other Noncurrent Assets	(439.5)	(131.0)
Change in Other Noncurrent Liabilities	41.4	189.9
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(176.4)	(209.3)
Fuel, Materials and Supplies	114.3	111.3
Accounts Payable	286.9	77.0
Accrued Taxes, Net	(468.5)	(301.3)
Other Current Assets	10.6	(144.0)
Other Current Liabilities	(170.7)	108.6
Net Cash Flows from Operating Activities	2,671.1	2,904.2
INVESTING ACTIVITIES		
Construction Expenditures	(4,020.2)	(3,318.3)
Purchases of Investment Securities	(1,336.5)	(1,190.1)
Sales of Investment Securities	1,311.0	1,157.1
Acquisitions of Generation Facilities	(1,359.3)	—
Acquisitions of Nuclear Fuel	(45.6)	(69.8)
Proceeds from Sale of Equity Method Investment	—	114.0
Other Investing Activities	103.3	57.4
Net Cash Flows Used for Investing Activities	(5,347.3)	(3,249.7)
FINANCING ACTIVITIES		
Issuance of Common Stock	131.8	475.8
Issuance of Long-term Debt	3,163.2	3,663.3
Issuance of Short-term Debt with Original Maturities greater than 90 Days	319.9	376.6
Change in Short-term Debt with Original Maturities less than 90 Days, Net	(764.3)	(860.0)
Retirement of Long-term Debt	(1,324.1)	(1,769.1)
Redemption of Short-term Debt with Original Maturities Greater than 90 Days	(577.8)	(665.1)
Principal Payments for Finance Lease Obligations	(25.0)	(35.8)
Proceeds from the Midwest Transmission Holdings Noncontrolling Interest Transaction, Net of Transaction Costs	2,782.9	—
Dividends Paid on Common Stock	(1,000.5)	(936.0)
Other Financing Activities	2.7	(35.3)
Net Cash Flows from Financing Activities	2,708.8	214.4
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	32.6	(131.1)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	246.0	379.0
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 278.6	$ 247.9
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 946.2	$ 881.0
Net Cash Paid for Income Taxes	59.3	60.8
Cash Paid (Received) for Transferable Tax Credits	(17.2)	(72.2)
Noncash Acquisitions Under Finance Leases	16.7	20.5
Construction Expenditures Included in Current Liabilities as of June 30,	1,059.1	1,049.9
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	33.4	8.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions of KWhs)			
Retail:				
Residential	3,275	3,529	6,191	6,058
Commercial	4,719	4,143	8,818	7,450
Industrial	3,300	3,324	6,670	6,597
Miscellaneous	147	156	291	307
Total Retail	11,441	11,152	21,970	20,412

Summary of Heating and Cooling Degree Days

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in degree days)			
Actual – Heating	4	1	296	162
Normal – Heating	4	3	208	198
Actual – Cooling	992	1,198	1,153	1,344
Normal – Cooling	909	949	1,021	1,086

AEP Texas Inc. and Subsidiaries
Reconciliation of 2024 to 2025 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Net Income	$ 128.4	$ 208.1
Changes in Revenues:		
Retail Revenues	23.9	81.9
Transmission Revenues	(9.3)	8.0
Other Revenues	(23.0)	(41.7)
Total Change in Revenues	(8.4)	48.2
Changes in Expenses and Other:		
Other Operation and Maintenance	(24.5)	(52.1)
Depreciation and Amortization	18.1	25.9
Taxes Other Than Income Taxes	1.6	(4.9)
Interest Income	(1.7)	(2.0)
Allowance for Equity Funds Used During Construction	(3.0)	(0.1)
Non-Service Cost Components of Net Periodic Benefit Cost	1.9	4.0
Interest Expense	(1.4)	(13.0)
Total Change in Expenses and Other	(9.0)	(42.2)
Income Tax Expense	10.1	8.6
2025 Net Income	$ 121.1	$ 222.7

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Retail Revenues** increased $24 million primarily due to the following:
  - A $35 million increase in base case and rider revenues.

  This increase was partially offset by:
  - A $7 million decrease in weather-normalized revenues primarily in the residential class.
  - A $4 million decrease in weather-related usage primarily due to a 17% decrease in cooling degree days.
- **Transmission Revenues** decreased $9 million primarily due to the following:
  - A $35 million decrease due to lower peak loads included in the 2025 billing rates.

  This decrease was partially offset by:
  - A $25 million increase in interim rates driven by increased transmission investments.
- **Other Revenues** decreased $23 million primarily due to the maturity of Transition Funding III LLC securitization bonds in December 2024.

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

- **Other Operation and Maintenance** expenses increased $25 million primarily due to the following:
  - A $29 million increase in recoverable transmission expenses.
  - A $16 million increase in transmission and distribution-related expenses.

  These increases were partially offset by:
  - A $20 million decrease in employee-related expenses due to the voluntary severance program that occurred in the second quarter of 2024.

- **Depreciation and Amortization** expenses decreased $18 million primarily due to:
  - A $16 million decrease in the amortization of securitized transition assets due to the maturity of Transition Funding III LLC securitization bonds in December 2024.
  - An $11 million decrease due to the deferral of eligible costs related to HB 5247.

  These decreases were partially offset by:
  - A $9 million increase due to a higher depreciable base.
- **Interest Expense** increased $1 million primarily due to the following:
  - An $8 million increase due to higher debt balances and interest rates.
  - A $5 million increase due to a decrease in capitalization of AFUDC on prepaid pension and OPEB.

  These increases were partially offset by:
  - A $12 million decrease due to the deferral of eligible costs related to HB 5247.
- **Income Tax Expense** decreased $10 million primarily due to an increase in amortization of Excess ADIT.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Retail Revenues** increased $82 million primarily due to the following:
  - A $76 million increase in base case and rider revenues.
  - A $12 million increase in weather-related usage primarily due to an 83% increase in heating degree days.

  These increases were partially offset by:
  - A $6 million decrease in weather-normalized revenues primarily in the residential class.
- **Transmission Revenues** increased $8 million due to the following:
  - A $42 million increase in interim rates driven by increased transmission investments.

  This increase was partially offset by:
  - A $34 million decrease due to lower peak loads included in the 2025 billing rates.
- **Other Revenues** decreased $42 million primarily due to the maturity of Transition Funding III LLC securitization bonds in December 2024.

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

- **Other Operation and Maintenance** expenses increased $52 million primarily due to the following:
  - A $42 million increase in recoverable transmission expenses.
  - An $18 million increase in transmission and distribution-related expenses.
  - A $7 million increase in property and liability insurance expenses.

  These increases were partially offset by:
  - A $20 million decrease in employee-related expenses due to the voluntary severance program that occurred in the second quarter of 2024.
- **Depreciation and Amortization** expenses decreased $26 million primarily due to the following:
  - A $32 million decrease in the amortization of securitized transition assets due to the maturity of Transition Funding III LLC securitization bonds in December 2024.
  - An $11 million decrease due to the deferral of eligible costs related to HB 5247.

  These decreases were partially offset by:
  - A $19 million increase due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $5 million primarily due to higher property taxes driven by increased investment.
- **Interest Expense** increased $13 million primarily due to the following:
  - A $19 million increase due to higher debt balances and interest rates.
  - A $5 million increase due to a decrease in capitalization of AFUDC on prepaid pension and OPEB.

  These increases were partially offset by:
  - A $12 million decrease due to the deferral of eligible costs related to HB 5247.
- **Income Tax Expense** decreased $9 million primarily due to an increase in amortization of Excess ADIT.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	**2024**	**2025**	**2024**
REVENUES				
Electric Transmission and Distribution	$ 528.3	$ 537.7	$ 1,048.3	$ 1,000.7
Sales to AEP Affiliates	1.4	1.4	2.7	2.7
Other Revenues	1.5	0.5	3.2	2.6
TOTAL REVENUES	531.2	539.6	1,054.2	1,006.0
EXPENSES				
Other Operation	163.8	147.8	330.0	288.6
Maintenance	30.2	21.7	54.5	43.8
Depreciation and Amortization	106.8	124.9	215.7	241.6
Taxes Other Than Income Taxes	39.0	40.6	85.5	80.6
TOTAL EXPENSES	339.8	335.0	685.7	654.6
OPERATING INCOME	191.4	204.6	368.5	351.4
Other Income (Expense):				
Interest Income	0.4	2.1	0.6	2.6
Allowance for Equity Funds Used During Construction	12.5	15.5	24.0	24.1
Non-Service Cost Components of Net Periodic Benefit Cost	5.3	3.4	11.1	7.1
Interest Expense	(60.7)	(59.3)	(133.8)	(120.8)
INCOME BEFORE INCOME TAX EXPENSE	148.9	166.3	270.4	264.4
Income Tax Expense	27.8	37.9	47.7	56.3
NET INCOME	$ 121.1	$ 128.4	$ 222.7	$ 208.1

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
Net Income	$ 121.1	$ 128.4	$ 222.7	$ 208.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $(0.1) and $0.6 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $(0.1) and $1.6 for the Six Months Ended June 30, 2025 and 2024, Respectively	(0.2)	2.2	(0.4)	6.1
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(0.2)	2.2	(0.4)	6.1
TOTAL COMPREHENSIVE INCOME	$ 120.9	$ 130.6	$ 222.3	$ 214.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	$ 2,092.4	$ 2,795.2	$ (3.0)	$ 4,884.6
Net Income		101.6		101.6
Other Comprehensive Loss			(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2025	2,092.4	2,896.8	(3.2)	4,986.0
Capital Contribution from Parent	250.5			250.5
Net Income		121.1		121.1
Other Comprehensive Loss			(0.2)	(0.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2025	$ 2,342.9	$ 3,017.9	$ (3.4)	$ 5,357.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2025 and December 31, 2024
(in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 0.1	$ 0.1
Restricted Cash (June 30, 2025 and December 31, 2024 Amounts Include $13.3 and $23.5, Respectively, Related to Transition Funding and Restoration Funding)	13.3	23.5
Advances to Affiliates	7.1	7.2
Accounts Receivable:		
Customers	200.8	182.8
Affiliated Companies	12.4	10.7
Accrued Unbilled Revenues	108.2	97.2
Miscellaneous	0.1	0.3
Allowance for Credit Losses	(4.1)	(4.3)
Total Accounts Receivable	317.4	286.7
Materials and Supplies	148.6	169.5
Prepayments and Other Current Assets	6.5	13.4
TOTAL CURRENT ASSETS	493.0	500.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	7,942.7	7,546.2
Distribution	6,501.1	6,250.5
Other Property, Plant and Equipment	1,198.4	1,175.7
Construction Work in Progress	1,183.6	1,118.0
Total Property, Plant and Equipment	16,825.8	16,090.4
Accumulated Depreciation and Amortization	2,144.3	2,046.9
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	14,681.5	14,043.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	383.3	353.6
Securitized Assets (June 30, 2025 and December 31, 2024 Amounts Include $105.1 and $116.7, Respectively, Related to Restoration Funding)	105.1	116.7
Operating Lease Assets	51.0	54.4
Deferred Charges and Other Noncurrent Assets	194.5	131.0
TOTAL OTHER NONCURRENT ASSETS	733.9	655.7
TOTAL ASSETS	$ 15,908.4	$ 15,199.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2025 and December 31, 2024
(in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT LIABILITIES		
Advances from Affiliates	$ 109.5	$ 284.9
Accounts Payable:		
General	318.2	366.2
Affiliated Companies	28.7	34.9
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2025 and December 31, 2024 Amounts Include $24.7 and $24.4, Respectively, Related to Restoration Funding)	774.7	324.5
Accrued Taxes	141.7	127.1
Accrued Interest (June 30, 2025 and December 31, 2024 Amounts Include $0.9 and $1.9, Respectively, Related to Restoration Funding)	57.4	55.0
Obligations Under Operating Leases	12.8	13.1
Other Current Liabilities	183.0	201.4
TOTAL CURRENT LIABILITIES	1,626.0	1,407.1
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2025 and December 31, 2024 Amounts Include $90.1 and $102.4, Respectively, Related to Restoration Funding)	6,057.6	6,117.1
Deferred Income Taxes	1,378.2	1,322.7
Regulatory Liabilities and Deferred Investment Tax Credits	1,285.6	1,285.4
Obligations Under Operating Leases	40.6	43.4
Deferred Credits and Other Noncurrent Liabilities	163.0	139.3
TOTAL NONCURRENT LIABILITIES	8,925.0	8,907.9
TOTAL LIABILITIES	10,551.0	10,315.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	2,342.9	2,092.4
Retained Earnings	3,017.9	2,795.2
Accumulated Other Comprehensive Income (Loss)	(3.4)	(3.0)
TOTAL COMMON SHAREHOLDER'S EQUITY	5,357.4	4,884.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 15,908.4	$ 15,199.6

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
OPERATING ACTIVITIES		
Net Income	$ 222.7	$ 208.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	215.7	241.6
Deferred Income Taxes	36.4	45.1
Allowance for Equity Funds Used During Construction	(24.0)	(24.1)
Pension Contributions to Qualified Plan Trust	(12.0)	—
Property Taxes	(57.9)	(53.5)
Change in Other Noncurrent Assets	(49.9)	(57.0)
Change in Other Noncurrent Liabilities	35.1	19.7
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(30.7)	(73.1)
Materials and Supplies	20.9	5.0
Accounts Payable	2.6	26.0
Accrued Taxes, Net	14.6	43.6
Other Current Assets	8.1	—
Other Current Liabilities	(22.8)	4.7
Net Cash Flows from Operating Activities	358.8	386.1
INVESTING ACTIVITIES		
Construction Expenditures	(863.4)	(665.3)
Change in Advances to Affiliates, Net	0.1	(251.1)
Other Investing Activities	32.3	32.8
Net Cash Flows Used for Investing Activities	(831.0)	(883.6)
FINANCING ACTIVITIES		
Capital Contribution from Parent	250.5	1.6
Issuance of Long-term Debt – Nonaffiliated	399.8	841.9
Change in Advances from Affiliates, Net	(175.4)	(103.7)
Retirement of Long-term Debt – Nonaffiliated	(12.2)	(244.5)
Principal Payments for Finance Lease Obligations	(3.7)	(3.7)
Other Financing Activities	3.0	1.3
Net Cash Flows from Financing Activities	462.0	492.9
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(10.2)	(4.6)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	23.6	34.1
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 13.4	$ 29.5
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 124.8	$ 111.0
Net Cash Paid (Received) for Income Taxes	(8.4)	(5.4)
Noncash Acquisitions Under Finance Leases	3.9	2.1
Construction Expenditures Included in Current Liabilities as of June 30,	207.1	191.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of June 30, 2025	As of June 30, 2024
	(in millions)	
Plant In Service	$ 16,089.7	$ 14,608.3
Construction Work in Progress	2,105.1	1,914.5
Accumulated Depreciation and Amortization	1,759.6	1,436.8
Total Transmission Property, Net	$ 16,435.2	$ 15,086.0

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of 2024 to 2025 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Earnings Attributable to Common Shareholder	$ 175.7	$ 356.9
Changes in Transmission Revenues:		
Transmission Revenues	266.6	310.9
Total Change in Transmission Revenues	266.6	310.9
Changes in Expenses and Other:		
Other Operation and Maintenance	2.8	3.6
Depreciation and Amortization	(12.2)	(20.4)
Taxes Other Than Income Taxes	(0.3)	(1.0)
Interest Income	(2.9)	(4.4)
Allowance for Equity Funds Used During Construction	(1.0)	3.5
Interest Expense	(5.2)	(5.4)
Total Change in Expenses and Other	(18.8)	(24.1)
Income Tax Expense	193.0	184.3
Net Income Attributable to Noncontrolling Interest	(60.7)	(60.7)
2025 Earnings Attributable to Common Shareholder	$ 555.8	$ 767.3

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Transmission Revenues** increased $267 million primarily due to the following:
  - A $214 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $49 million increase due to continued transmission investment.

Expenses and Other, Income Tax Expense and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- **Depreciation and Amortization** expenses increased $12 million primarily due to a higher depreciable base.
- **Interest Expense** increased $5 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** decreased $193 million primarily due to the following:
  - A $254 million decrease due to a reduction in Excess ADIT as a result of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $52 million increase due to an increase in pretax book income.
- **Net Income Attributable to Noncontrolling Interest** increased $61 million due to the Midwest Transmission noncontrolling interest transaction that closed in June 2025.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Transmission Revenues** increased $311 million primarily due to the following:
  - A $214 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $96 million increase due to continued transmission investment.

Expenses and Other, Income Tax Expense and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- **Depreciation and Amortization** expenses increased $20 million due to a higher depreciable base.
- **Interest Expense** increased $5 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** decreased $184 million primarily due to the following:
  - A $254 million decrease due to a reduction in Excess ADIT as a result of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $60 million increase due to an increase in pretax book income.
- **Net Income Attributable to Noncontrolling Interest** increased $61 million due to the Midwest Transmission noncontrolling interest transaction that closed in June 2025.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
REVENUES				
Transmission Revenues	$ 110.7	$ 97.3	$ 216.7	$ 195.7
Sales to AEP Affiliates	469.9	394.4	900.1	783.8
(Provision for)/Reversal of – Revenue Refund – Affiliated	127.2	(16.6)	119.8	(22.6)
(Provision for)/ Reversal of – Revenue Refund – Nonaffiliated	33.9	(0.3)	32.2	(1.7)
Other Revenues	0.1	0.4	0.1	2.8
TOTAL REVENUES	741.8	475.2	1,268.9	958.0
EXPENSES				
Other Operation	35.8	40.0	64.8	69.9
Maintenance	6.4	5.0	11.8	10.3
Depreciation and Amortization	118.9	106.7	233.0	212.6
Taxes Other Than Income Taxes	75.8	75.5	149.9	148.9
TOTAL EXPENSES	236.9	227.2	459.5	441.7
OPERATING INCOME	504.9	248.0	809.4	516.3
Other Income (Expense):				
Interest Income – Affiliated	1.4	4.3	1.8	6.2
Allowance for Equity Funds Used During Construction	21.5	22.5	43.9	40.4
Interest Expense	(56.6)	(51.4)	(111.6)	(106.2)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	471.2	223.4	743.5	456.7
Income Tax Expense (Benefit)	(145.3)	47.7	(84.5)	99.8
NET INCOME	616.5	175.7	828.0	356.9
Net Income Attributable to Noncontrolling Interest	60.7	—	60.7	—
EARNINGS ATTRIBUTABLE TO AEPTCo COMMON SHAREHOLDER	$ 555.8	$ 175.7	$ 767.3	$ 356.9

AEPTCo is wholly-owned by AEP Transmission Holdco.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Noncontrolling Interest	Total
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2023	$ 3,043.4	$ 3,289.9	$ —	$ 6,333.3
Capital Contribution from AEP Member	25.0			25.0
Dividends Paid to AEP 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 AEP Member	9.6			9.6
Dividends Paid to AEP 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
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2024	$ 3,100.6	$ 3,850.3	$ —	$ 6,950.9
Capital Contribution from AEP Member	32.5			32.5
Dividends Paid to AEP Member		(42.5)		(42.5)
Net Income		211.5		211.5
TOTAL MEMBER'S EQUITY – MARCH 31, 2025	3,133.1	4,019.3	—	7,152.4
Capital Contribution from AEP Member	8.3			8.3
Dividends Paid to AEP Member		(2,835.8)		(2,835.8)
Midwest Transmission Holdings Noncontrolling Interest Transaction	1,790.5		992.4	2,782.9
Net Income		555.8	60.7	616.5
TOTAL MEMBER'S EQUITY – JUNE 30, 2025	$ 4,931.9	$ 1,739.3	$ 1,053.1	$ 7,724.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2025 and December 31, 2024
(in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT ASSETS		
Advances to Affiliates	$ 67.9	$ 30.4
Accounts Receivable:		
Customers	68.7	58.9
Affiliated Companies	170.7	134.1
Miscellaneous	—	1.3
Total Accounts Receivable	239.4	194.3
Prepayments and Other Current Assets	14.9	11.1
TOTAL CURRENT ASSETS	322.2	235.8
TRANSMISSION PROPERTY		
Transmission Property	15,544.3	14,913.4
Other Property, Plant and Equipment	545.4	516.1
Construction Work in Progress	2,105.1	1,965.4
Total Transmission Property	18,194.8	17,394.9
Accumulated Depreciation and Amortization	1,759.6	1,578.4
TOTAL TRANSMISSION PROPERTY – NET	16,435.2	15,816.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	56.3	0.4
Deferred Property Taxes	177.5	308.9
Deferred Charges and Other Noncurrent Assets	41.6	8.7
TOTAL OTHER NONCURRENT ASSETS	275.4	318.0
TOTAL ASSETS	$ 17,032.8	$ 16,370.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
June 30, 2025 and December 31, 2024
(Unaudited)

	June 30, 2025	December 31, 2024
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 47.7	$ 84.7
Accounts Payable:		
General	335.9	360.5
Affiliated Companies	107.3	117.0
Long-term Debt Due Within One Year – Nonaffiliated	—	90.0
Accrued Taxes	476.2	665.9
Accrued Interest	47.3	44.9
Obligations Under Operating Leases	1.2	1.3
Other Current Liabilities	44.4	44.5
TOTAL CURRENT LIABILITIES	1,060.0	1,408.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	6,098.5	5,678.1
Deferred Income Taxes	1,484.6	1,278.6
Regulatory Liabilities	643.2	878.4
Obligations Under Operating Leases	1.6	1.2
Deferred Credits and Other Noncurrent Liabilities	20.6	174.3
TOTAL NONCURRENT LIABILITIES	8,248.5	8,010.6
TOTAL LIABILITIES	9,308.5	9,419.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	4,931.9	3,100.6
Retained Earnings	1,739.3	3,850.3
TOTAL MEMBER'S EQUITY	6,671.2	6,950.9
Noncontrolling Interest	1,053.1	—
TOTAL EQUITY	7,724.3	6,950.9
TOTAL LIABILITIES AND EQUITY	$ 17,032.8	$ 16,370.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
OPERATING ACTIVITIES		
Net Income	$ 828.0	$ 356.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	233.0	212.6
Deferred Income Taxes	(136.5)	49.4
Allowance for Equity Funds Used During Construction	(43.9)	(40.4)
Property Taxes	131.4	116.2
Change in Other Noncurrent Assets	(44.9)	—
Change in Other Noncurrent Liabilities	(152.3)	(28.9)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(45.1)	(23.8)
Materials and Supplies	—	(0.2)
Accounts Payable	5.3	(6.5)
Accrued Taxes, Net	(201.9)	(65.3)
Other Current Assets	7.9	0.5
Other Current Liabilities	(15.7)	2.6
Net Cash Flows from Operating Activities	565.3	573.1
INVESTING ACTIVITIES		
Construction Expenditures	(786.9)	(657.8)
Change in Advances to Affiliates, Net	(37.5)	(208.1)
Other Investing Activities	21.7	11.3
Net Cash Flows Used for Investing Activities	(802.7)	(854.6)
FINANCING ACTIVITIES		
Capital Contribution from Member	40.8	34.6
Issuance of Long-term Debt – Nonaffiliated	419.0	445.7
Retirement of Long-term Debt – Nonaffiliated	(90.0)	—
Change in Advances from Affiliates, Net	(37.0)	(127.8)
Proceeds from the Midwest Transmission Holdings Noncontrolling Interest Transaction, Net of Transaction Costs	2,782.9	—
Dividends Paid to Member	(2,878.3)	(71.0)
Net Cash Flows from Financing Activities	237.4	281.5
Net Change in Cash and Cash Equivalents	—	—
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 106.7	$ 96.9
Net Cash Paid (Received) for Income Taxes	(21.1)	(12.5)
Construction Expenditures Included in Current Liabilities as of June 30,	218.9	237.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions of KWhs)			
Retail:				
Residential	2,032	2,085	5,686	5,350
Commercial	1,465	1,454	2,965	2,929
Industrial	2,204	2,203	4,280	4,305
Miscellaneous	208	203	419	414
Total Retail	5,909	5,945	13,350	12,998
Wholesale (a)	576	564	1,303	1,218
Total KWhs	6,485	6,509	14,653	14,216

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

Summary of Heating and Cooling Degree Days

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in degree days)			
Actual – Heating	69	48	1,433	1,029
Normal – Heating	80	85	1,359	1,395
Actual – Cooling	417	535	428	537
Normal – Cooling	387	378	393	384

Appalachian Power Company and Subsidiaries
Reconciliation of 2024 to 2025 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Net Income	$ 58.3	$ 194.8
Changes in Revenues:		
Retail Revenues	20.0	106.7
Off-system Sales	0.7	1.2
Transmission Revenues	14.3	15.6
Other Revenues	2.4	(6.2)
Total Change in Revenues	37.4	117.3
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	14.0	3.6
Other Operation and Maintenance	(4.9)	(12.2)
Depreciation and Amortization	(25.1)	(38.3)
Taxes Other Than Income Taxes	3.4	8.9
Interest Income	0.5	0.7
Allowance for Equity Funds Used During Construction	(0.1)	1.4
Non-Service Cost Components of Net Periodic Benefit Cost	(1.1)	(3.0)
Interest Expense	(1.9)	(1.4)
Total Change in Expenses and Other	(15.2)	(40.3)
Income Tax Expense	26.4	(0.3)
2025 Net Income	$ 106.9	$ 271.5

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Retail Revenues** increased $20 million primarily due to the following:
  - A $10 million increase in fuel revenues.
  - A $7 million increase in weather-normalized margins primarily in the residential and commercial classes.
  - A $7 million increase in rider revenues.

  These increases were partially offset by:
  - A $7 million decrease in weather-related usage primarily due to a 22% decrease in cooling degree days.
- **Transmission Revenues** increased $14 million primarily due to the following:
  - A $10 million increase due to continued transmission investment.
  - A $6 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $14 million primarily due to the impact to the West Virginia ENEC as a result of the June 2025 FERC NOLC order.
- **Other Operation and Maintenance** expenses increased $5 million primarily due to the following:
  - A $24 million increase in transmission expenses primarily due to:
    - A $15 million increase due to the June 2025 FERC NOLC order.
    - A $5 million increase in recoverable expenses.
    - A $5 million increase in vegetation management expenses.
  - A $6 million increase due to recoverable energy assistance program expenses for qualified Virginia customers.

These increases were partially offset by:
    - A $23 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
- **Depreciation and Amortization** expenses increased $25 million primarily due to a higher depreciable base.
- **Income Tax Expense** decreased $26 million primarily due to a reduction in Excess ADIT as a result of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Retail Revenues** increased $107 million primarily due to the following:
    - A $35 million increase in fuel revenues.
    - A $34 million increase in weather-related usage primarily due to a 39% increase in heating degree days, partially offset by a 20% decrease in cooling degree days.
    - A $30 million increase in rider revenues.
- **Transmission Revenues** increased $16 million primarily due to the following:
    - A $12 million increase due to continued transmission investment.
    - A $6 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** decreased $6 million primarily due to a decrease in sales of renewable energy credits.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $4 million primarily due to the following:
    - An $18 million decrease due to the prior year amortization of Excess ADIT through the West Virginia ENEC.
    - A $17 million decrease due to the impact to the West Virginia ENEC as a result of the June 2025 FERC NOLC order.

    These decreases were partially offset by:
    - A $27 million increase in load and purchased power prices as well as an increase in West Virginia ENEC rates resulting in higher amortization of deferred fuel regulatory assets.
- **Other Operation and Maintenance** expenses increased $12 million primarily due to the following:
    - A $27 million increase in transmission expenses primarily due to:
        - A $15 million increase due to the June 2025 FERC NOLC order.
        - A $7 million increase in recoverable expenses.
        - A $5 million increase in vegetation management and Virginia storm-related expenses.
    - A $14 million increase due to recoverable energy assistance program expenses for qualified Virginia customers.

    These increases were partially offset by:
    - A $25 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
- **Depreciation and Amortization** expenses increased $38 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** decreased $9 million primarily due to lower business and occupation taxes.
- **Income Tax Expense** remained consistent primarily due to the following:
    - A $16 million increase due to an increase in pretax book income.
    - A $13 million increase due to a decrease in amortization of Excess ADIT.

    These increases were partially offset by:
    - A $23 million decrease due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
    - A $5 million decrease due to an increase in flow-through cost of removal.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	**2024**	**2025**	**2024**
REVENUES				
Electric Generation, Transmission and Distribution	$ 876.2	$ 851.7	$ 1,973.7	$ 1,876.0
Sales to AEP Affiliates	66.2	54.8	138.2	117.9
Other Revenues	5.2	3.7	8.6	9.3
TOTAL REVENUES	947.6	910.2	2,120.5	2,003.2
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	290.8	304.8	698.0	701.6
Other Operation	210.8	212.0	433.0	424.6
Maintenance	84.4	78.3	162.1	158.3
Depreciation and Amortization	170.8	145.7	333.8	295.5
Taxes Other Than Income Taxes	38.8	42.2	79.3	88.2
TOTAL EXPENSES	795.6	783.0	1,706.2	1,668.2
OPERATING INCOME	152.0	127.2	414.3	335.0
Other Income (Expense):				
Interest Income	1.7	1.2	2.7	2.0
Allowance for Equity Funds Used During Construction	4.2	4.3	8.6	7.2
Non-Service Cost Components of Net Periodic Benefit Cost	5.3	6.4	10.5	13.5
Interest Expense	(70.0)	(68.1)	(137.6)	(136.2)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	93.2	71.0	298.5	221.5
Income Tax Expense (Benefit)	(13.7)	12.7	27.0	26.7
NET INCOME	$ 106.9	$ 58.3	$ 271.5	$ 194.8

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	**2024**	**2025**	**2024**
Net Income	$ 106.9	$ 58.3	$ 271.5	$ 194.8
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $(0.1) and $(0.1) for the Six Months Ended June 30, 2025 and 2024, Respectively	(0.2)	(0.2)	(0.4)	(0.4)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.1) and $0 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $(0.1) and $(0.1) for the Six Months Ended June 30, 2025 and 2024, Respectively	(0.1)	(0.3)	(0.2)	(0.6)
TOTAL OTHER COMPREHENSIVE LOSS	(0.3)	(0.5)	(0.6)	(1.0)
TOTAL COMPREHENSIVE INCOME	$ 106.6	$ 57.8	$ 270.9	$ 193.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2024	$ 260.4	$ 1,944.1	$ 3,532.2	$ 11.3	$ 5,748.0
Common Stock Dividends			(50.0)		(50.0)
Net Income			164.6		164.6
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2025	260.4	1,944.1	3,646.8	11.0	5,862.3
Capital Contribution from Parent		7.2			7.2
Net Income			106.9		106.9
Other Comprehensive Loss				(0.3)	(0.3)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2025	$ 260.4	$ 1,951.3	$ 3,753.7	$ 10.7	$ 5,976.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2025 and December 31, 2024
(in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6.2	$ 3.9
Restricted Cash for Securitized Funding	18.2	16.2
Advances to Affiliates	18.1	17.7
Accounts Receivable:		
Customers	192.7	185.7
Affiliated Companies	114.5	110.5
Accrued Unbilled Revenues	76.0	93.1
Miscellaneous	0.9	0.3
Allowance for Credit Losses	(2.2)	(2.0)
Total Accounts Receivable	381.9	387.6
Fuel	267.8	308.0
Materials and Supplies	133.9	131.7
Risk Management Assets	108.7	35.7
Regulatory Asset for Under-Recovered Fuel Costs	128.3	148.1
Prepayments and Other Current Assets	25.0	46.0
TOTAL CURRENT ASSETS	1,088.1	1,094.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	7,257.8	7,272.6
Transmission	5,106.1	5,001.5
Distribution	5,762.6	5,568.5
Other Property, Plant and Equipment	1,145.5	1,062.9
Construction Work in Progress	775.1	742.6
Total Property, Plant and Equipment	20,047.1	19,648.1
Accumulated Depreciation and Amortization	6,212.0	6,035.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	13,835.1	13,612.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,451.3	1,366.0
Securitized Assets	92.2	106.2
Employee Benefits and Pension Assets	211.8	203.9
Operating Lease Assets	69.1	67.0
Deferred Charges and Other Noncurrent Assets	174.4	215.4
TOTAL OTHER NONCURRENT ASSETS	1,998.8	1,958.5
TOTAL ASSETS	$ 16,922.0	$ 16,665.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2025 and December 31, 2024
(Unaudited)

	June 30, 2025	December 31, 2024
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 172.9	$ 95.0
Accounts Payable:		
General	392.6	427.2
Affiliated Companies	136.7	205.9
Long-term Debt Due Within One Year – Nonaffiliated	271.1	798.6
Customer Deposits	98.8	86.6
Accrued Taxes	127.9	168.8
Obligations Under Operating Leases	14.9	13.7
Other Current Liabilities	181.0	229.7
TOTAL CURRENT LIABILITIES	1,395.9	2,025.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	5,500.9	4,861.7
Deferred Income Taxes	2,079.8	2,033.5
Regulatory Liabilities and Deferred Investment Tax Credits	1,070.1	1,115.8
Asset Retirement Obligations	785.1	767.4
Employee Benefits and Pension Obligations	28.0	29.6
Obligations Under Operating Leases	54.7	54.0
Deferred Credits and Other Noncurrent Liabilities	31.4	30.4
TOTAL NONCURRENT LIABILITIES	9,550.0	8,892.4
TOTAL LIABILITIES	10,945.9	10,917.9
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,951.3	1,944.1
Retained Earnings	3,753.7	3,532.2
Accumulated Other Comprehensive Income (Loss)	10.7	11.3
TOTAL COMMON SHAREHOLDER'S EQUITY	5,976.1	5,748.0
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 16,922.0	$ 16,665.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
OPERATING ACTIVITIES		
Net Income	$ 271.5	$ 194.8
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	333.8	295.5
Deferred Income Taxes	(4.5)	(27.4)
Allowance for Equity Funds Used During Construction	(8.6)	(7.2)
Mark-to-Market of Risk Management Contracts	(72.6)	(54.4)
Deferred Fuel Over/Under-Recovery, Net	6.4	81.2
Change in Regulatory Assets	(117.6)	1.2
Change in Other Noncurrent Assets	28.5	(0.7)
Change in Other Noncurrent Liabilities	6.4	5.9
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	5.7	(32.2)
Fuel, Materials and Supplies	38.0	45.4
Margin Deposits	17.9	(12.4)
Accounts Payable	(60.9)	66.4
Accrued Taxes, Net	(38.6)	41.6
Other Current Assets	(0.1)	2.3
Other Current Liabilities	(19.1)	10.8
Net Cash Flows from Operating Activities	386.2	610.8
INVESTING ACTIVITIES		
Construction Expenditures	(527.6)	(443.5)
Change in Advances to Affiliates, Net	(0.4)	(23.6)
Other Investing Activities	4.0	9.1
Net Cash Flows Used for Investing Activities	(524.0)	(458.0)
FINANCING ACTIVITIES		
Capital Contribution from Parent	7.2	109.5
Issuance of Long-term Debt – Nonaffiliated	528.2	480.8
Change in Advances from Affiliates, Net	77.9	(339.6)
Retirement of Long-term Debt – Nonaffiliated	(418.4)	(399.5)
Principal Payments for Finance Lease Obligations	(4.3)	(4.4)
Dividends Paid on Common Stock	(50.0)	—
Other Financing Activities	1.5	0.4
Net Cash Flows from (Used for) Financing Activities	142.1	(152.8)
Net Increase in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	4.3	—
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	20.1	19.9
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 24.4	$ 19.9
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 134.4	$ 126.6
Net Cash Paid (Received) for Income Taxes	(18.5)	9.6
Cash Paid (Received) for Transferable Tax Credits	—	(0.1)
Noncash Acquisitions Under Finance Leases	2.2	0.7
Construction Expenditures Included in Current Liabilities as of June 30,	115.4	143.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions of KWhs)			
Retail:				
Residential	1,097	1,162	2,650	2,600
Commercial	1,414	1,290	2,686	2,565
Industrial	1,856	1,853	3,604	3,661
Miscellaneous	9	11	22	25
Total Retail	4,376	4,316	8,962	8,851
Wholesale (a)	1,507	1,117	3,943	2,737
Total KWhs	5,883	5,433	12,905	11,588

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

Summary of Heating and Cooling Degree Days

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in degree days)			
Actual – Heating	217	141	2,335	1,826
Normal – Heating	237	241	2,365	2,422
Actual – Cooling	280	357	280	357
Normal – Cooling	284	268	285	269

Indiana Michigan Power Company and Subsidiaries
Reconciliation of 2024 to 2025 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Net Income	$ 35.2	$ 180.2
Changes in Revenues:		
Retail Revenues	82.7	133.4
Off-system Sales	56.8	62.6
Transmission Revenues	9.9	10.7
Other Revenues	(6.5)	(9.0)
Total Change in Revenues	142.9	197.7
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(46.3)	(99.5)
Purchased Electricity from AEP Affiliates	(21.9)	(36.4)
Other Operation and Maintenance	(11.8)	(12.2)
Asset Impairments and Other Related Charges	13.4	13.4
Depreciation and Amortization	(10.4)	(26.1)
Taxes Other Than Income Taxes	3.0	0.1
Other Income	0.6	2.0
Non-Service Cost Components of Net Periodic Benefit Cost	(1.3)	(2.8)
Interest Expense	(1.9)	(10.5)
Total Change in Expenses and Other	(76.6)	(172.0)
Income Tax Benefit	22.6	(24.3)
2025 Net Income	$ 124.1	$ 181.6

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Retail Revenues** increased $83 million primarily due to the following:
  - A $35 million increase due to the implementation of new base rates in Indiana and Michigan.
  - A $34 million increase in weather-normalized margins primarily in the commercial class.
  - A $23 million increase in rider revenues.
  - A $20 million increase in fuel revenues.

  These increases were partially offset by:
  - A $22 million decrease due to regulatory provisions for refund.
  - A $6 million decrease in weather-related usage primarily due to a 21% decrease in cooling degree days.
- **Off-system Sales** increased $57 million primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales.
- **Transmission Revenues** increased $10 million primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** decreased $7 million primarily due to a decrease in River Transportation Division (RTD) barging revenues.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $46 million primarily due to an increase in recoverable fuel and purchased power costs and an increase in Rockport Plant, Unit 2 merchant generation fuel costs.
- **Purchased Electricity from AEP Affiliates** increased $22 million primarily due to an increase in purchased electricity from AEGCo.

- **Other Operation and Maintenance** expenses increased $12 million primarily due to the following:
  - A $21 million increase in vegetation management expenses.
  - A $6 million increase in nuclear expenses at Cook Plant.

  These increases were partially offset by:
  - A $12 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
  - A $6 million decrease in demand side management expenses.
- **Asset Impairments and Other Related Charges** decreased $13 million due to the Federal EPA's revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses increased $10 million primarily due to the following:
  - A $5 million increase due to a higher depreciable base.
  - A $3 million increase in regulatory reserves related to Nuclear PTCs.
- **Income Tax Benefit** increased $23 million primarily due to the following:
  - A $32 million increase due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - An $18 million increase due to an increase in deferred ITC amortization and PTCs.

  These increases were partially offset by:
  - A $14 million decrease due to an increase in pretax book income.
  - A $13 million decrease in amortization of Excess ADIT.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Retail Revenues** increased $133 million primarily due to the following:
  - A $78 million increase due to the implementation of new base rates in Indiana and Michigan.
  - A $61 million increase in fuel revenues.
  - A $35 million increase in weather-normalized margins primarily in the residential and commercial classes, partially offset by a decrease in the industrial class.
  - A $16 million increase in rider revenues.
  - A $7 million increase in weather-related usage primarily due to a 28% increase in heating degree days.

  These increases were partially offset by:
  - A $71 million decrease due to regulatory provisions for refund.
- **Off-system Sales** increased $63 million primarily due to economic hedging activity and Rockport Plant, Unit 2 merchant sales.
- **Transmission Revenues** increased $11 million primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** decreased $9 million primarily due to the following:
  - A $6 million decrease in RTD barging revenues.
  - A $4 million decrease in sales of renewable energy credits.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $100 million primarily due to an increase in recoverable fuel and purchased power costs and an increase in Rockport Plant, Unit 2, merchant generation fuel costs, partially offset by a decrease due to a prior year purchased power disallowance from the MPSC order on the 2021 PSCR reconciliation.
- **Purchased Electricity from AEP Affiliates** increased $36 million primarily due to an increase in purchased electricity from AEGCo.
- **Other Operation and Maintenance** expenses increased $12 million primarily due to the following:
  - A $28 million increase in distribution expenses primarily due to an increase in vegetation management costs.
  - A $7 million increase in transmission expenses primarily due to an $11 million increase in recoverable PJM expenses, partially offset by a $5 million decrease primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  These increases were partially offset by:
  - A $13 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
  - A $12 million decrease in demand side management expenses.

- **Asset Impairments and Other Related Charges** decreased $13 million due to the Federal EPA's revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses increased $26 million primarily due to the following:
  - A $9 million increase due to a higher depreciable base.
  - A $9 million increase due to a prior year deferral of Excess ADIT as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs.
  - A $5 million increase in regulatory reserves related to Nuclear PTCs.
- **Interest Expense** increased $11 million primarily due to a prior year deferral of expenses as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking.
- **Income Tax Benefit** decreased $24 million primarily due to the following:
  - A $55 million decrease 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 ratemaking recorded in 2024.
  - A $17 million decrease in amortization of Excess ADIT.
  - A $5 million decrease due to an increase in pretax book income.

  These decreases were partially offset by:
  - A $32 million increase due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $24 million increase due to an increase in PTCs.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	**2024**	**2025**	**2024**
REVENUES				
Electric Generation, Transmission and Distribution	$ 735.6	$ 574.9	$ 1,494.7	$ 1,232.3
Sales to AEP Affiliates	1.5	5.4	5.4	7.7
(Provision for)/Reversal of – Revenue Refund – Affiliated	9.2	(3.3)	8.5	(3.8)
Provision for Refund – Nonaffiliated	(25.7)	(5.3)	(83.9)	(14.9)
Other Revenues – Affiliated	14.4	20.5	29.9	35.5
Other Revenues – Nonaffiliated	2.2	2.1	4.8	4.9
TOTAL REVENUES	737.2	594.3	1,459.4	1,261.7
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	132.4	86.1	308.2	208.7
Purchased Electricity from AEP Affiliates	66.4	44.5	142.4	106.0
Other Operation	177.5	190.3	348.4	368.5
Maintenance	87.8	63.2	147.9	115.6
Asset Impairments and Other Related Charges	—	13.4	—	13.4
Depreciation and Amortization	128.7	118.3	252.7	226.6
Taxes Other Than Income Taxes	21.6	24.6	47.8	47.9
TOTAL EXPENSES	614.4	540.4	1,247.4	1,086.7
OPERATING INCOME	122.8	53.9	212.0	175.0
Other Income (Expense):				
Other Income	3.8	3.2	8.4	6.4
Non-Service Cost Components of Net Periodic Benefit Cost	5.2	6.5	10.4	13.2
Interest Expense	(38.9)	(37.0)	(73.7)	(63.2)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	92.9	26.6	157.1	131.4
Income Tax Expense (Benefit)	(31.2)	(8.6)	(24.5)	(48.8)
NET INCOME	$ 124.1	$ 35.2	$ 181.6	$ 180.2

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	**2024**	**2025**	**2024**
Net Income	$ 124.1	$ 35.2	$ 181.6	$ 180.2
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0.1 and $0.1 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $0.1 and $0.1 for the Six Months Ended June 30, 2025 and 2024, Respectively	0.1	0.1	0.2	0.2
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $0 and $0 for the Six Months Ended June 30, 2025 and 2024, Respectively	0.1	(0.1)	0.1	(0.1)
TOTAL OTHER COMPREHENSIVE INCOME	0.2	—	0.3	0.1
TOTAL COMPREHENSIVE INCOME	$ 124.3	$ 35.2	$ 181.9	$ 180.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2024	$ 56.6	$ 1,011.7	$ 2,328.0	$ 0.2	$ 3,396.5
Common Stock Dividends			(50.0)		(50.0)
Net Income			57.5		57.5
Other Comprehensive Income				0.1	0.1
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2025	56.6	1,011.7	2,335.5	0.3	3,404.1
Capital Contribution from Parent		7.4			7.4
Net Income			124.1		124.1
Other Comprehensive Income				0.2	0.2
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2025	$ 56.6	$ 1,019.1	$ 2,459.6	$ 0.5	$ 3,535.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2025 and December 31, 2024
(in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.5	$ 1.5
Accounts Receivable:		
Customers	62.6	58.7
Affiliated Companies	81.6	79.1
Accrued Unbilled Revenues	25.5	21.4
Miscellaneous	5.3	6.3
Total Accounts Receivable	175.0	165.5
Fuel	54.6	83.4
Materials and Supplies	214.9	212.2
Risk Management Assets	12.3	18.4
Regulatory Asset for Under-Recovered Fuel Costs	5.0	10.6
Prepayments and Other Current Assets	60.2	52.0
TOTAL CURRENT ASSETS	525.5	543.6
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,460.1	5,503.0
Transmission	1,978.1	1,957.8
Distribution	3,692.0	3,535.0
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	1,062.9	992.4
Construction Work in Progress	390.1	334.9
Total Property, Plant and Equipment	12,583.2	12,323.1
Accumulated Depreciation, Depletion and Amortization	4,786.8	4,643.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,796.4	7,679.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	616.1	548.1
Spent Nuclear Fuel and Decommissioning Trusts	4,609.7	4,395.1
Operating Lease Assets	59.0	51.5
Deferred Charges and Other Noncurrent Assets	290.1	317.9
TOTAL OTHER NONCURRENT ASSETS	5,574.9	5,312.6
TOTAL ASSETS	$ 13,896.8	$ 13,535.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2025 and December 31, 2024
(dollars in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT LIABILITIES		
Advances from Affiliates	$ 25.7	$ 126.8
Accounts Payable:		
General	250.3	202.2
Affiliated Companies	94.3	98.5
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2025 and December 31, 2024 Amounts Include $94.6 and $79.0, Respectively, Related to DCC Fuel)	94.6	269.2
Customer Deposits	54.6	59.1
Accrued Taxes	101.5	102.2
Accrued Interest	41.6	41.3
Obligations Under Operating Leases	14.9	12.3
Regulatory Liability for Over-Recovered Fuel Costs	13.5	10.3
Other Current Liabilities	162.9	149.3
TOTAL CURRENT LIABILITIES	853.9	1,071.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,416.3	3,225.1
Deferred Income Taxes	1,185.1	1,175.8
Regulatory Liabilities and Deferred Investment Tax Credits	2,636.3	2,480.8
Asset Retirement Obligations	2,135.0	2,088.8
Obligations Under Operating Leases	45.0	40.1
Deferred Credits and Other Noncurrent Liabilities	89.4	57.2
TOTAL NONCURRENT LIABILITIES	9,507.1	9,067.8
TOTAL LIABILITIES	10,361.0	10,139.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	1,019.1	1,011.7
Retained Earnings	2,459.6	2,328.0
Accumulated Other Comprehensive Income (Loss)	0.5	0.2
TOTAL COMMON SHAREHOLDER'S EQUITY	3,535.8	3,396.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 13,896.8	$ 13,535.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Six Months Ended June 30,	
	2025	2024
OPERATING ACTIVITIES		
Net Income	$ 181.6	$ 180.2
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	252.7	226.6
Deferred Income Taxes	(45.7)	(69.8)
Deferral of Incremental Nuclear Refueling Outage Expenses, Net	(22.8)	(20.5)
Asset Impairments and Other Related Charges	—	13.4
Allowance for Equity Funds Used During Construction	(8.1)	(6.7)
Mark-to-Market of Risk Management Contracts	6.6	9.5
Amortization of Nuclear Fuel	51.8	46.1
Deferred Fuel Over/Under-Recovery, Net	8.8	(9.5)
Change in Other Noncurrent Assets	(13.9)	10.2
Change in Other Noncurrent Liabilities	55.3	29.3
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(9.5)	(0.1)
Fuel, Materials and Supplies	26.1	8.6
Accounts Payable	27.8	(7.5)
Accrued Taxes, Net	(0.7)	36.1
Other Current Assets	2.5	(8.8)
Other Current Liabilities	(13.6)	(10.8)
Net Cash Flows from Operating Activities	498.9	426.3
INVESTING ACTIVITIES		
Construction Expenditures	(305.7)	(275.0)
Purchases of Investment Securities	(1,330.0)	(1,187.1)
Sales of Investment Securities	1,294.4	1,154.1
Acquisitions of Nuclear Fuel	(45.6)	(69.8)
Other Investing Activities	27.2	3.7
Net Cash Flows Used for Investing Activities	(359.7)	(374.1)
FINANCING ACTIVITIES		
Capital Contribution from Parent	7.4	5.0
Issuance of Long-term Debt – Nonaffiliated	249.0	80.4
Change in Advances from Affiliates, Net	(101.1)	(10.7)
Retirement of Long-term Debt – Nonaffiliated	(240.0)	(48.6)
Principal Payments for Finance Lease Obligations	(3.1)	(3.6)
Dividends Paid on Common Stock	(50.0)	(75.0)
Other Financing Activities	0.6	0.6
Net Cash Flows Used for Financing Activities	(137.2)	(51.9)
Net Increase in Cash and Cash Equivalents	2.0	0.3
Cash and Cash Equivalents at Beginning of Period	1.5	2.1
Cash and Cash Equivalents at End of Period	$ 3.5	$ 2.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 71.5	$ 72.8
Net Cash Paid (Received) for Income Taxes	2.9	(14.5)
Noncash Acquisitions Under Finance Leases	1.4	1.0
Construction Expenditures Included in Current Liabilities as of June 30,	81.8	86.2
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	33.4	8.2

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

OHIO POWER COMPANY AND SUBSIDIARIES

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions of KWhs)			
Retail:				
Residential	3,024	3,064	7,119	6,815
Commercial	6,323	5,066	11,812	9,750
Industrial	3,748	3,502	7,134	7,041
Miscellaneous	25	24	53	53
Total Retail (a)	13,120	11,656	26,118	23,659
Wholesale (b)	464	253	1,131	843
Total KWhs	13,584	11,909	27,249	24,502

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

Summary of Heating and Cooling Degree Days

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in degree days)			
Actual – Heating	170	110	2,077	1,573
Normal – Heating	173	181	1,993	2,052
Actual – Cooling	336	422	342	422
Normal – Cooling	323	306	325	309

Ohio Power Company and Subsidiaries
Reconciliation of 2024 to 2025 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Net Income	$ 18.4	$ 89.0
Changes in Revenues:		
Retail Revenues	14.3	(17.5)
Off-system Sales	12.9	25.8
Transmission Revenues	3.1	6.2
Other Revenues	(7.6)	(12.1)
Total Change in Revenues	22.7	2.4
Changes in Expenses and Other:		
Purchased Electricity for Resale	(3.9)	7.9
Purchased Electricity from AEP Affiliates	10.7	41.4
Other Operation and Maintenance	4.6	(27.2)
Asset Impairments and Other Related Charges	52.9	52.9
Depreciation and Amortization	7.2	19.1
Taxes Other Than Income Taxes	17.0	9.1
Other Income	(0.9)	—
Allowance for Equity Funds Used During Construction	2.8	4.3
Non-Service Cost Components of Net Periodic Benefit Cost	(1.0)	(2.2)
Interest Expense	(3.0)	(6.8)
Total Change in Expenses and Other	86.4	98.5
Income Tax Expense	(25.6)	(26.3)
Equity Earnings of Unconsolidated Subsidiaries	0.9	2.2
2025 Net Income	$ 102.8	$ 165.8

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Retail Revenues** increased $14 million primarily due to the following:
  - A $24 million increase in weather-normalized revenues primarily in the commercial and industrial classes.
  - An $8 million increase in rider revenues.

  These increases were partially offset by:
  - An $11 million decrease due to lower prices and lower customer participation in OPCo's SSO.
  - A $5 million decrease in weather-related usage driven by a 20% decrease in cooling degree days.
- **Off-system Sales** increased $13 million primarily due to increased sales of OVEC purchased power driven by higher market prices and volume.
- **Other Revenues** decreased $8 million primarily due to lower third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.

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

- **Purchased Electricity from AEP Affiliates** expenses decreased $11 million primarily due to decreased recoverable purchases to serve SSO customers.

- **Other Operation and Maintenance** expenses decreased $5 million primarily due to the following:
  - A $13 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
  - A $9 million decrease related to recoverable energy assistance program expenses for qualified Ohio customers.

  These decreases were partially offset by:
  - An $8 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.
  - An $8 million increase in distribution expenses primarily related to recoverable storm restoration costs and recoverable vegetation management expenses.
- **Asset Impairments and Other Related Charges** decreased $53 million primarily due to the Federal EPA's revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses decreased $7 million primarily due to capital rider under-recoveries.
- **Taxes Other Than Income Taxes** decreased $17 million primarily due to the following:
  - A $12 million decrease in property taxes.
  - A $6 million decrease in state excise taxes due to decreased billed KWhs in 2025.
- **Income Tax Expense** increased $26 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Retail Revenues** decreased $18 million primarily due to the following:
  - An $88 million decrease due to lower prices and lower customer participation in OPCo's SSO.
  - A $4 million decrease in weather-normalized revenues primarily in the residential class partially offset by an increase in the commercial class.

  These decreases were partially offset by:
  - A $57 million increase in rider revenues.
  - A $22 million increase in weather-related usage driven by a 32% increase in heating degree days.
- **Off-system Sales** increased $26 million primarily due to increased sales of OVEC purchased power driven by higher market prices and volume.
- **Transmission Revenues** increased $6 million primarily due to continued transmission investment.
- **Other Revenues** decreased $12 million primarily due to the following:
  - A $7 million decrease in recoverable sales of renewable energy credits.
  - A $5 million decrease due to lower third-party Legacy Generation Resource Rider revenue related to the recovery of OVEC costs.

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

- **Purchased Electricity for Resale** expenses decreased $8 million primarily due to the following:
  - A $41 million decrease in recoverable auction purchases primarily due to lower prices.
  - A $12 million decrease in recoverable alternative energy rider expenses.

  These decreases were partially offset by:
  - A $30 million estimated reduction in regulatory assets for OVEC-related purchased power costs that are no longer probable of future recovery due to recently approved legislation in Ohio.
  - A $17 million increase in recoverable OVEC costs.
- **Purchased Electricity from AEP Affiliates** expenses decreased $41 million primarily due to decreased recoverable purchases to serve SSO customers.
- **Other Operation and Maintenance** expenses increased $27 million primarily due to the following:
  - A $58 million increase in transmission expenses primarily due to an increase in recoverable PJM expenses.

  This increase was partially offset by:
  - A $19 million decrease related to recoverable energy assistance program expenses for qualified Ohio customers.
  - A $12 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
- **Asset Impairments and Other Related Charges** decreased $53 million primarily due to the Federal EPA's revised CCR rules finalized in 2024.
- **Depreciation and Amortization** expenses decreased $19 million primarily due to capital rider under-recoveries.
- **Taxes Other Than Income Taxes** decreased $9 million primarily due to lower property taxes.
- **Interest Expense** increased $7 million primarily due to higher debt balances.
- **Income Tax Expense** increased $26 million primarily due to an increase in pretax book income.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
REVENUES				
Electricity, Transmission and Distribution	$ 910.1	$ 887.8	$ 1,900.3	$ 1,903.2
Sales to AEP Affiliates	6.3	5.7	16.0	11.4
Other Revenues	2.6	2.8	6.2	5.5
TOTAL REVENUES	919.0	896.3	1,922.5	1,920.1
EXPENSES				
Purchased Electricity for Resale	188.9	185.0	435.8	443.7
Purchased Electricity from AEP Affiliates	14.8	25.5	30.7	72.1
Other Operation	283.3	283.8	617.0	577.0
Maintenance	63.0	67.1	115.6	128.4
Asset Impairments and Other Related Charges	—	52.9	—	52.9
Depreciation and Amortization	94.8	102.0	188.7	207.8
Taxes Other Than Income Taxes	120.3	137.3	279.0	288.1
TOTAL EXPENSES	765.1	853.6	1,666.8	1,770.0
OPERATING INCOME	153.9	42.7	255.7	150.1
Other Income (Expense):				
Other Income	—	0.9	0.9	0.9
Allowance for Equity Funds Used During Construction	7.1	4.3	14.1	9.8
Non-Service Cost Components of Net Periodic Benefit Cost	4.3	5.3	8.6	10.8
Interest Expense	(39.6)	(36.6)	(78.0)	(71.2)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	125.7	16.6	201.3	100.4
Income Tax Expense (Benefit)	23.0	(2.6)	36.9	10.6
Equity Earnings of Unconsolidated Subsidiaries	0.1	(0.8)	1.4	(0.8)
NET INCOME	$ 102.8	$ 18.4	$ 165.8	$ 89.0

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	$ 321.2	$ 1,020.0	$ 2,542.9	$ 3,884.1
Common Stock Dividends			(46.0)	(46.0)
Net Income			63.0	63.0
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2025	321.2	1,020.0	2,559.9	3,901.1
Capital Contribution from Parent		1.8		1.8
Common Stock Dividends			(25.0)	(25.0)
Net Income			102.8	102.8
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2025	$ 321.2	$ 1,021.8	$ 2,637.7	$ 3,980.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2025 and December 31, 2024
(in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 8.2	$ 4.5
Advances to Affiliates	—	114.9
Accounts Receivable:		
Customers	167.3	189.2
Affiliated Companies	120.8	117.5
Accrued Unbilled Revenues	51.2	31.1
Miscellaneous	4.7	8.6
Total Accounts Receivable	344.0	346.4
Materials and Supplies	177.7	141.4
Prepayments and Other Current Assets	12.1	19.9
TOTAL CURRENT ASSETS	542.0	627.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	3,744.8	3,663.9
Distribution	7,389.7	7,244.0
Other Property, Plant and Equipment	1,258.6	1,256.0
Construction Work in Progress	818.9	691.1
Total Property, Plant and Equipment	13,212.0	12,855.0
Accumulated Depreciation and Amortization	2,945.7	2,883.9
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,266.3	9,971.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	364.1	379.1
Operating Lease Assets	55.6	60.4
Deferred Charges and Other Noncurrent Assets	408.9	661.0
TOTAL OTHER NONCURRENT ASSETS	828.6	1,100.5
TOTAL ASSETS	$ 11,636.9	$ 11,698.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2025 and December 31, 2024
(Unaudited)

	June 30, 2025	December 31, 2024
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 203.0	$ —
Accounts Payable:		
General	340.2	343.6
Affiliated Companies	169.4	204.9
Risk Management Liabilities	5.9	7.3
Customer Deposits	92.8	108.1
Accrued Taxes	529.8	836.1
Obligations Under Operating Leases	12.0	12.3
Other Current Liabilities	166.5	182.2
TOTAL CURRENT LIABILITIES	1,519.6	1,694.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,717.1	3,715.7
Long-term Risk Management Liabilities	41.8	40.2
Deferred Income Taxes	1,225.1	1,201.1
Regulatory Liabilities and Deferred Investment Tax Credits	917.9	987.7
Obligations Under Operating Leases	43.9	48.4
Deferred Credits and Other Noncurrent Liabilities	190.8	127.0
TOTAL NONCURRENT LIABILITIES	6,136.6	6,120.1
TOTAL LIABILITIES	7,656.2	7,814.6
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	1,021.8	1,020.0
Retained Earnings	2,637.7	2,542.9
TOTAL COMMON SHAREHOLDER'S EQUITY	3,980.7	3,884.1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 11,636.9	$ 11,698.7

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
OPERATING ACTIVITIES		
Net Income	$ 165.8	$ 89.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	188.7	207.8
Deferred Income Taxes	13.7	(10.2)
Asset Impairments and Other Related Charges	—	52.9
Allowance for Equity Funds Used During Construction	(14.1)	(9.8)
Mark-to-Market of Risk Management Contracts	0.2	(7.5)
Property Taxes	205.8	190.8
Change in Other Noncurrent Assets	41.3	4.8
Change in Other Noncurrent Liabilities	(9.0)	18.4
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	2.4	(80.4)
Materials and Supplies	(19.0)	9.7
Accounts Payable	(4.9)	(47.2)
Customer Deposits	(15.3)	39.0
Accrued Taxes, Net	(305.7)	(207.1)
Other Current Assets	7.2	(4.9)
Other Current Liabilities	(23.3)	11.1
Net Cash Flows from Operating Activities	233.8	256.4
INVESTING ACTIVITIES		
Construction Expenditures	(504.3)	(455.8)
Change in Advances to Affiliates, Net	114.9	(49.9)
Other Investing Activities	26.8	15.3
Net Cash Flows Used for Investing Activities	(362.6)	(490.4)
FINANCING ACTIVITIES		
Capital Contribution from Parent	1.8	—
Issuance of Long-term Debt – Nonaffiliated	—	346.3
Change in Advances from Affiliates, Net	203.0	(110.5)
Principal Payments for Finance Lease Obligations	(2.3)	(2.7)
Dividends Paid on Common Stock	(71.0)	—
Other Financing Activities	1.0	0.8
Net Cash Flows from Financing Activities	132.5	233.9
Net Increase (Decrease) in Cash and Cash Equivalents	3.7	(0.1)
Cash and Cash Equivalents at Beginning of Period	4.5	6.4
Cash and Cash Equivalents at End of Period	$ 8.2	$ 6.3
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 72.4	$ 64.6
Net Cash Paid (Received) for Income Taxes	1.3	(13.0)
Noncash Acquisitions Under Finance Leases	1.1	0.8
Construction Expenditures Included in Current Liabilities as of June 30,	121.3	112.9

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

PUBLIC SERVICE COMPANY OF OKLAHOMA

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions of KWhs)			
Retail:				
Residential	1,319	1,463	2,911	2,914
Commercial	1,485	1,383	2,806	2,615
Industrial	1,483	1,501	2,860	2,912
Miscellaneous	325	327	604	610
Total Retail	4,612	4,674	9,181	9,051
Wholesale (a)	28	64	85	111
Total KWhs	4,640	4,738	9,266	9,162

(a) Includes municipalities and cooperatives, unit power and other wholesale customers.

Summary of Heating and Cooling Degree Days

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in degree days)			
Actual – Heating	31	5	1,193	917
Normal – Heating	43	42	1,081	1,088
Actual – Cooling	605	808	629	830
Normal – Cooling	709	665	729	682

Public Service Company of Oklahoma
Reconciliation of 2024 to 2025 Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Net Income	$ 36.3	$ 108.3
Changes in Revenues:		
Retail Revenues (a)	10.7	20.8
Transmission Revenues	9.0	12.1
Other Revenues	(9.0)	(16.0)
Total Change in Revenues	10.7	16.9
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	7.7	27.6
Other Operation and Maintenance	(8.6)	(13.2)
Depreciation and Amortization	(3.0)	(4.1)
Taxes Other Than Income Taxes	4.1	2.8
Interest Income	0.1	1.8
Allowance for Equity Funds Used During Construction	2.1	2.9
Non-Service Cost Components of Net Periodic Benefit Cost	(0.6)	(1.4)
Interest Expense	(2.1)	(15.9)
Total Change in Expenses and Other	(0.3)	0.5
Income Tax Benefit	17.0	(34.5)
2025 Net Income	$ 63.7	$ 91.2

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

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Retail Revenues** increased $11 million primarily due to the following:
  - A $36 million increase in base rate and rider revenues.
  - A $12 million increase in weather-normalized margins primarily in the residential class.

  These increases were partially offset by:
  - A $20 million decrease in weather-related usage primarily driven by a 25% decrease in cooling degree days.
  - A $20 million decrease in fuel revenue primarily due to lower authorized fuel rates.
- **Transmission Revenues** increased $9 million primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** decreased $9 million primarily due to revenues from a customer project to enhance transmission resiliency in 2024.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $8 million primarily due to increased fuel and purchased power costs, and lower authorized fuel rates resulting in lower current amortization of under-recovered deferred fuel regulatory assets.
- **Other Operation and Maintenance** expenses increased $9 million primarily due to the following:
  - A $19 million increase in transmission-related expenses primarily due to the June 2025 FERC NOLC order.
  - A $7 million increase in overhead line maintenance expenses.

These increases were partially offset by:

- A $10 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
- A $9 million decrease in expenses from a customer project to enhance transmission resiliency in 2024.

- **Income Tax Benefit** increased $17 million primarily due to the following:
  - A $13 million increase due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $7 million increase due to an increase in PTCs.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Retail Revenues** increased $21 million primarily due to the following:
  - A $64 million increase in base rate and rider revenues.
  - An $11 million increase in weather-normalized margins primarily in the residential class partially offset by a decrease in the industrial class.

  These increases were partially offset by:
  - A $50 million decrease in fuel revenue primarily due to lower authorized fuel rates.
  - A $12 million decrease in weather-related usage primarily driven by a 24% decrease in cooling degree days.
- **Transmission Revenues** increased $12 million primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates and continued transmission investment.
- **Other Revenues** decreased $16 million primarily due to revenues from a customer project to enhance transmission resiliency in 2024.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $28 million primarily due to increased fuel and purchased power costs and lower authorized fuel rates resulting in increased deferred fuel balances.
- **Other Operation and Maintenance** expenses increased $13 million primarily due to the following:
  - A $25 million increase in transmission-related expenses primarily due to the June 2025 FERC NOLC order and SPP expenses.
  - A $10 million increase in overhead line maintenance expenses.

  These increases were partially offset by:
  - A $13 million decrease in expenses from a customer project to enhance transmission resiliency in 2024.
  - A $10 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
- **Interest Expense** increased $16 million primarily due to higher long-term debt balances and a prior year deferral of expenses as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking.
- **Income Tax Benefit** decreased $35 million primarily due to the following:
  - A $48 million decrease 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 ratemaking recorded in 2024.

  This decrease was partially offset by:
  - A $13 million increase due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	**2024**	**2025**	**2024**
REVENUES				
Electric Generation, Transmission and Distribution	$ 466.5	$ 448.1	$ 856.0	$ 826.2
Sales to AEP Affiliates	1.2	1.1	2.4	4.6
Other Revenues	1.8	9.6	5.1	15.8
TOTAL REVENUES	469.5	458.8	863.5	846.6
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	172.3	180.0	301.3	328.9
Other Operation	122.4	119.3	223.7	215.9
Maintenance	30.4	24.9	58.4	53.0
Depreciation and Amortization	67.1	64.1	135.6	131.5
Taxes Other Than Income Taxes	20.3	24.4	38.6	41.4
TOTAL EXPENSES	412.5	412.7	757.6	770.7
OPERATING INCOME	57.0	46.1	105.9	75.9
Other Income (Expense):				
Interest Income	0.4	0.3	2.3	0.5
Allowance for Equity Funds Used During Construction	3.0	0.9	6.2	3.3
Non-Service Cost Components of Net Periodic Benefit Cost	2.1	2.7	4.2	5.6
Interest Expense	(29.0)	(26.9)	(59.6)	(43.7)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	33.5	23.1	59.0	41.6
Income Tax Expense (Benefit)	(30.2)	(13.2)	(32.2)	(66.7)
NET INCOME	$ 63.7	$ 36.3	$ 91.2	$ 108.3

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
Net Income	$ 63.7	$ 36.3	$ 91.2	$ 108.3
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $(0.3) and $0 for the Six Months Ended June 30, 2025 and 2024, Respectively	—	—	(1.2)	—
TOTAL COMPREHENSIVE INCOME	$ 63.7	$ 36.3	$ 90.0	$ 108.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	$ 157.2	$ 1,041.2	$ 1,483.6	$ 3.6	$ 2,685.6
Net Income			27.5		27.5
Other Comprehensive Loss				(1.2)	(1.2)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2025	157.2	1,041.2	1,511.1	2.4	2,711.9
Capital Contribution from Parent		299.9			299.9
Net Income			63.7		63.7
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2025	$ 157.2	$ 1,341.1	$ 1,574.8	$ 2.4	$ 3,075.5

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2025 and December 31, 2024
(in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.8	$ 1.8
Advances to Affiliates	—	232.0
Accounts Receivable:		
Customers	86.4	74.8
Affiliated Companies	59.8	32.6
Miscellaneous	0.1	0.3
Total Accounts Receivable	146.3	107.7
Fuel	9.6	17.1
Materials and Supplies	117.1	108.8
Risk Management Assets	96.9	20.6
Accrued Tax Benefits	35.3	35.5
Regulatory Asset for Under-Recovered Fuel Costs	139.0	64.7
Prepayments and Other Current Assets	35.7	20.2
TOTAL CURRENT ASSETS	583.7	608.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	3,990.3	2,772.4
Transmission	1,368.6	1,345.3
Distribution	3,851.7	3,698.8
Other Property, Plant and Equipment	1,263.2	550.0
Construction Work in Progress	390.5	378.8
Total Property, Plant and Equipment	10,864.3	8,745.3
Accumulated Depreciation and Amortization	2,660.7	2,213.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,203.6	6,532.3
OTHER NONCURRENT ASSETS		
Regulatory Assets	551.9	527.8
Employee Benefits and Pension Assets	76.6	73.6
Operating Lease Assets	118.6	106.2
Deferred Charges and Other Noncurrent Assets	70.7	62.0
TOTAL OTHER NONCURRENT ASSETS	817.8	769.6
TOTAL ASSETS	$ 9,605.1	$ 7,910.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2025 and December 31, 2024
(Unaudited)

	June 30, 2025	December 31, 2024
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 319.7	$ —
Accounts Payable:		
General	329.7	200.5
Affiliated Companies	59.6	59.1
Long-term Debt Due Within One Year – Nonaffiliated	0.6	125.6
Risk Management Liabilities	5.6	5.8
Customer Deposits	83.1	72.9
Accrued Taxes	78.8	33.4
Accrued Interest	47.6	33.1
Obligations Under Operating Leases	10.5	10.4
Other Current Liabilities	78.1	78.6
TOTAL CURRENT LIABILITIES	1,013.3	619.4
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,523.4	2,730.0
Deferred Income Taxes	995.7	930.6
Regulatory Liabilities and Deferred Investment Tax Credits	698.2	689.7
Asset Retirement Obligations	133.9	118.8
Obligations Under Operating Leases	114.8	101.9
Deferred Credits and Other Noncurrent Liabilities	50.3	34.3
TOTAL NONCURRENT LIABILITIES	5,516.3	4,605.3
TOTAL LIABILITIES	6,529.6	5,224.7
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	1,341.1	1,041.2
Retained Earnings	1,574.8	1,483.6
Accumulated Other Comprehensive Income (Loss)	2.4	3.6
TOTAL COMMON SHAREHOLDER'S EQUITY	3,075.5	2,685.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 9,605.1	$ 7,910.3

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
OPERATING ACTIVITIES		
Net Income	$ 91.2	$ 108.3
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	135.6	131.5
Deferred Income Taxes	40.2	8.2
Allowance for Equity Funds Used During Construction	(6.2)	(3.3)
Mark-to-Market of Risk Management Contracts	(72.6)	(37.5)
Property Taxes	(32.2)	(29.7)
Deferred Fuel Over/Under-Recovery, Net	(74.3)	(13.8)
Change in Other Regulatory Assets	(25.1)	(4.2)
Change in Other Noncurrent Assets	3.2	(13.7)
Change in Other Noncurrent Liabilities	(7.5)	(6.2)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(38.6)	(21.4)
Fuel, Materials and Supplies	3.2	(3.7)
Accounts Payable	120.7	109.8
Accrued Taxes, Net	44.8	(7.9)
Other Current Assets	(16.0)	(27.4)
Other Current Liabilities	(0.7)	(52.2)
Net Cash Flows from Operating Activities	165.7	136.8
INVESTING ACTIVITIES		
Construction Expenditures	(325.2)	(270.8)
Change in Advances to Affiliates, Net	232.0	—
Acquisitions of Generation Facilities	(1,359.3)	—
Other Investing Activities	1.0	(2.2)
Net Cash Flows Used for Investing Activities	(1,451.5)	(273.0)
FINANCING ACTIVITIES		
Capital Contribution from Parent	299.9	0.2
Issuance of Long-term Debt – Nonaffiliated	793.8	—
Change in Advances from Affiliates, Net	319.7	207.4
Retirement of Long-term Debt – Nonaffiliated	(125.3)	(0.3)
Principal Payments for Finance Lease Obligations	(1.6)	(1.7)
Dividends Paid on Common Stock	—	(70.0)
Other Financing Activities	1.3	0.6
Net Cash Flows from Financing Activities	1,287.8	136.2
Net Increase in Cash and Cash Equivalents	2.0	—
Cash and Cash Equivalents at Beginning of Period	1.8	2.5
Cash and Cash Equivalents at End of Period	$ 3.8	$ 2.5
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 47.3	$ 51.6
Net Cash Paid (Received) for Income Taxes	(4.0)	(3.0)
Cash Paid (Received) for Transferable Tax Credits	(8.5)	(29.6)
Noncash Acquisitions Under Finance Leases	1.8	0.8
Construction Expenditures Included in Current Liabilities as of June 30,	91.3	61.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions of KWhs)			
Retail:				
Residential	1,365	1,391	2,968	2,900
Commercial	1,415	1,430	2,660	2,670
Industrial	1,327	1,414	2,508	2,641
Miscellaneous	18	18	34	35
Total Retail	4,125	4,253	8,170	8,246
Wholesale (a)	1,251	1,340	2,743	2,714
Total KWhs	5,376	5,593	10,913	10,960

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

Summary of Heating and Cooling Degree Days

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in degree days)			
Actual – Heating	9	5	726	560
Normal – Heating	24	24	714	721
Actual – Cooling	948	1,042	1,044	1,130
Normal – Cooling	770	754	816	798

Southwestern Electric Power Company
Reconciliation of 2024 to 2025
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2024 Earnings (Loss) Attributable to Common Shareholder	$ (70.1)	$ 138.0
Changes in Revenues:		
Retail Revenues (a)	158.5	173.4
Off-system Sales	(1.6)	(1.5)
Transmission Revenues	20.7	20.8
Other Revenues	(3.0)	(3.2)
Total Change in Revenues	174.6	189.5
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	0.9	(5.4)
Other Operation and Maintenance	12.5	30.1
Depreciation and Amortization	(6.6)	(26.1)
Taxes Other Than Income Taxes	(3.8)	(4.4)
Interest Income	(1.9)	(3.4)
Allowance for Equity Funds Used During Construction	0.3	0.2
Non-Service Cost Components of Net Periodic Benefit Cost	(0.7)	(1.6)
Interest Expense	(3.9)	(29.7)
Total Change in Expenses and Other	(3.2)	(40.3)
Income Tax Benefit	14.1	(123.7)
Equity Earnings of Unconsolidated Subsidiary	—	(0.1)
Net Income Attributable to Noncontrolling Interest	0.2	0.7
2025 Earnings Attributable to Common Shareholder	$ 115.6	$ 164.1

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

Second Quarter of 2025 Compared to Second Quarter of 2024

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

- **Retail Revenues** increased $159 million primarily due to a $160 million revenue refund provision recorded in 2024 associated with the Turk Plant and SWEPCo's 2012 Texas Base Rate Case.
- **Transmission Revenues** increased $21 million primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

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

- **Other Operation and Maintenance** expenses decreased $13 million primarily due to the following:
  - A $16 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
  - A $6 million decrease in distribution-related expenses primarily driven by storm costs in Arkansas.

  These decreases were partially offset by:
  - An $8 million increase in transmission-related expenses primarily due to the June 2025 FERC NOLC order.

- **Depreciation and Amortization** expenses increased $7 million primarily due to:
  - A $9 million increase due to a higher depreciable base.
  - A $4 million increase due to the amortization of the Storm Recovery Funding securitized assets.

  These increases were partially offset by:
  - A $4 million decrease due to an increase in regulatory assets related to NOLCs.
- **Income Tax Benefit** increased $14 million primarily due to the following:
  - A $42 million increase due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
  - A $5 million increase due to an increase in PTCs.

  These increases were partially offset by:
  - A $36 million decrease due to an increase in pretax book income.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

- **Retail Revenues** increased $173 million primarily due to the following:
  - A $160 million increase due to a revenue refund provision recorded in 2024 associated with the Turk Plant and SWEPCo's 2012 Texas Base Rate Case.
  - A $43 million increase in rider revenues.

  These increases were partially offset by:
  - A $31 million decrease in weather-normalized margins in all classes.
- **Transmission Revenues** increased $21 million primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $5 million primarily due to a current year decrease in amortization of under-recovered fuel regulatory assets.
- **Other Operation and Maintenance** expenses decreased $30 million primarily due to the following:
  - A $16 million decrease in employee-related expenses primarily due to the voluntary severance program that occurred in the second quarter of 2024.
  - A $14 million decrease 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.
  - A $6 million decrease in distribution-related expenses primarily driven by storm costs in Arkansas.

  These decreases were partially offset by:
  - A $7 million increase in transmission-related expenses primarily due to the June 2025 FERC NOLC order.
- **Depreciation and Amortization** expenses increased $26 million primarily due to:
  - A $17 million increase due to a higher depreciable base.
  - An $8 million increase due to the amortization of the Storm Recovery Funding securitized assets.
- **Interest Expense** increased $30 million primarily due to:
  - A $20 million increase due to a prior year deferral of expenses as a result of the IRS PLR received regarding the treatment of stand-alone NOLCs in retail ratemaking.
  - A $9 million increase associated with Storm Recovery Funding bonds.
- **Income Tax Benefit** decreased $124 million primarily due to the following:
  - A $109 million decrease 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 ratemaking recorded in 2024.
  - 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 denial of SWEPCo's request to allow the merchant portion of the Turk Plant to serve Arkansas customers recorded in 2024.
  - A $31 million decrease due to an increase in pretax book income.

  These decreases were partially offset by:
  - A $42 million increase due to a reduction in Excess ADIT primarily due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
REVENUES				
Electric Generation, Transmission and Distribution	$ 543.7	$ 546.1	$ 1,066.4	$ 1,055.4
Sales to AEP Affiliates	24.4	18.7	35.5	30.8
(Provision for)/Reversal of – Revenue Refund – Nonaffiliated	1.8	(171.4)	(4.5)	(180.5)
Other Revenues	0.5	2.4	4.1	6.3
TOTAL REVENUES	570.4	395.8	1,101.5	912.0
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	192.5	193.4	383.4	378.0
Other Operation	107.1	116.3	204.8	229.2
Maintenance	50.1	53.4	84.9	90.6
Depreciation and Amortization	107.8	101.2	206.0	179.9
Taxes Other Than Income Taxes	29.3	25.5	64.1	59.7
TOTAL EXPENSES	486.8	489.8	943.2	937.4
OPERATING INCOME (LOSS)	83.6	(94.0)	158.3	(25.4)
Other Income (Expense):				
Interest Income	2.4	4.3	4.9	8.3
Allowance for Equity Funds Used During Construction	3.7	3.4	7.0	6.8
Non-Service Cost Components of Net Periodic Benefit Cost	1.7	2.4	3.4	5.0
Interest Expense	(33.6)	(29.7)	(72.9)	(43.2)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	57.8	(113.6)	100.7	(48.5)
Income Tax Expense (Benefit)	(58.3)	(44.2)	(64.6)	(188.3)
Equity Earnings of Unconsolidated Subsidiary	0.3	0.3	0.6	0.7
NET INCOME (LOSS)	116.4	(69.1)	165.9	140.5
Net Income Attributable to Noncontrolling Interest	0.8	1.0	1.8	2.5
EARNINGS (LOSS) ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 115.6	$ (70.1)	$ 164.1	$ 138.0

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
Net Income (Loss)	$ 116.4	$ (69.1)	$ 165.9	$ 140.5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $0 and $0 for the Six Months Ended June 30, 2025 and 2024, Respectively	—	—	(0.1)	(0.1)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2025 and 2024, Respectively, and $0 and $0 for the Six Months Ended June 30, 2025 and 2024, Respectively	—	—	—	(0.1)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	—	—	(0.1)	(0.2)
TOTAL COMPREHENSIVE INCOME (LOSS)	116.4	(69.1)	165.8	140.3
Total Comprehensive Income Attributable to Noncontrolling Interest	0.8	1.0	1.8	2.5
TOTAL COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 115.6	$ (70.1)	$ 164.0	$ 137.8

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2025 and 2024
(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, 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
TOTAL EQUITY – DECEMBER 31, 2024	$ 0.1	$ 1,549.7	$ 2,352.5	$ 2.3	$ 0.4	$ 3,905.0
Common Stock Dividends – Nonaffiliated					(1.0)	(1.0)
Net Income			48.5		1.0	49.5
Other Comprehensive Loss				(0.1)		(0.1)
TOTAL EQUITY – MARCH 31, 2025	0.1	1,549.7	2,401.0	2.2	0.4	3,953.4
Capital Contribution from Parent		450.6				450.6
Common Stock Dividends – Nonaffiliated					(1.0)	(1.0)
Net Income			115.6		0.8	116.4
TOTAL EQUITY – JUNE 30, 2025	$ 0.1	$ 2,000.3	$ 2,516.6	$ 2.2	$ 0.2	$ 4,519.4

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2025 and December 31, 2024
(in millions)
(Unaudited)

	June 30, 2025	December 31, 2024
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.7	$ 1.2
Restricted Cash (June 30, 2025 and December 31, 2024 Amounts Include $16.7 and $3.4, Respectively, Related to Storm Recovery Funding)	16.7	3.4
Advances to Affiliates	78.7	2.3
Accounts Receivable:		
Customers	34.5	34.5
Affiliated Companies	46.6	54.1
Miscellaneous	8.8	9.2
Total Accounts Receivable	89.9	97.8
Fuel	88.0	86.5
Materials and Supplies (June 30, 2025 and December 31, 2024 Amounts Include $1.2 and $1.5, Respectively, Related to Sabine)	85.5	81.4
Risk Management Assets	70.4	18.1
Accrued Tax Benefits	57.6	26.0
Regulatory Asset for Under-Recovered Fuel Costs	109.6	106.6
Prepayments and Other Current Assets	35.4	14.7
TOTAL CURRENT ASSETS	635.5	438.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,325.1	5,287.5
Transmission	3,018.0	2,863.8
Distribution	3,122.2	3,007.1
Other Property, Plant and Equipment (June 30, 2025 and December 31, 2024 Amounts Include $129.3 and $166.8, Respectively, Related to Sabine)	912.7	940.4
Construction Work in Progress	688.9	627.3
Total Property, Plant and Equipment	13,066.9	12,726.1
Accumulated Depreciation and Amortization (June 30, 2025 and December 31, 2024 Amounts Include $129.3 and $166.8, Respectively, Related to Sabine)	3,395.0	3,280.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,671.9	9,446.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	944.9	921.3
Securitized Assets (June 30, 2025 and December 31, 2024 Amounts Include $323.6 and $331.4, Respectively, Related to Storm Recovery Funding)	323.6	331.4
Deferred Charges and Other Noncurrent Assets	379.3	358.2
TOTAL OTHER NONCURRENT ASSETS	1,647.8	1,610.9
TOTAL ASSETS	$ 11,955.2	$ 11,495.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2025 and December 31, 2024
(Unaudited)

	June 30, 2025	December 31, 2024
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 275.0
Accounts Payable:		
General	281.2	265.5
Affiliated Companies	92.7	57.1
Short-term Debt – Nonaffiliated	1.6	5.5
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2025 and December 31, 2024 Amounts Include $19.3 and $22.7, Respectively, Related to Storm Recovery Funding)	519.3	22.7
Risk Management Liabilities	3.3	2.3
Customer Deposits	75.5	75.4
Accrued Taxes	111.7	48.6
Accrued Interest	48.0	40.6
Obligations Under Operating Leases	6.6	8.2
Provision for Refund	84.6	70.8
Other Current Liabilities	141.3	159.9
TOTAL CURRENT LIABILITIES	1,365.8	1,031.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2025 and December 31, 2024 Amounts Include $312.6 and $308.7, Respectively, Related to Storm Recovery Funding)	3,463.7	3,958.1
Deferred Income Taxes	1,358.9	1,271.3
Regulatory Liabilities and Deferred Investment Tax Credits	549.4	610.8
Asset Retirement Obligations	270.2	257.5
Employee Benefits and Pension Obligations	38.9	46.5
Obligations Under Operating Leases	132.5	137.5
Provision for Refund	79.7	107.8
Storm Reserve	108.7	106.2
Deferred Credits and Other Noncurrent Liabilities	68.0	62.7
TOTAL NONCURRENT LIABILITIES	6,070.0	6,558.4
TOTAL LIABILITIES	7,435.8	7,590.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 3,680 Shares		
Outstanding – 3,680 Shares	0.1	0.1
Paid-in Capital	2,000.3	1,549.7
Retained Earnings	2,516.6	2,352.5
Accumulated Other Comprehensive Income (Loss)	2.2	2.3
TOTAL COMMON SHAREHOLDER'S EQUITY	4,519.2	3,904.6
Noncontrolling Interest	0.2	0.4
TOTAL EQUITY	4,519.4	3,905.0
TOTAL LIABILITIES AND EQUITY	$ 11,955.2	$ 11,495.0

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2025 and 2024
(in millions)
(Unaudited)

	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
OPERATING ACTIVITIES		
Net Income	$ 165.9	$ 140.5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	206.0	179.9
Deferred Income Taxes	17.9	(136.2)
Allowance for Equity Funds Used During Construction	(7.0)	(6.8)
Mark-to-Market of Risk Management Contracts	(50.9)	(31.1)
Pension Contributions to Qualified Plan Trust	(8.8)	—
Property Taxes	(45.0)	(47.4)
Deferred Fuel Over/Under-Recovery, Net	63.5	82.7
Provision for Refund – Turk Plant	—	133.3
Change in Other Noncurrent Assets	(26.7)	(12.8)
Change in Other Noncurrent Liabilities	(57.1)	(40.1)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	7.9	(43.0)
Fuel, Materials and Supplies	(5.6)	22.1
Accounts Payable	89.8	60.2
Accrued Taxes, Net	31.5	19.7
Provision for Refund – Turk Plant	—	26.7
Other Current Assets	(19.7)	(26.0)
Other Current Liabilities	(4.2)	(10.8)
Net Cash Flows from Operating Activities	357.5	310.9
INVESTING ACTIVITIES		
Construction Expenditures	(440.3)	(347.7)
Change in Advances to Affiliates, Net	(76.4)	(0.6)
Other Investing Activities	5.5	0.9
Net Cash Flows Used for Investing Activities	(511.2)	(347.4)
FINANCING ACTIVITIES		
Capital Contribution from Parent	450.6	—
Change in Short-term Debt – Nonaffiliated	(3.9)	1.4
Change in Advances from Affiliates, Net	(275.0)	196.7
Principal Payments for Finance Lease Obligations	(2.0)	(9.8)
Dividends Paid on Common Stock	—	(150.0)
Dividends Paid on Common Stock – Nonaffiliated	(2.0)	(2.4)
Other Financing Activities	1.8	0.6
Net Cash Flows from Financing Activities	169.5	36.5
Net Increase in Cash and Cash Equivalents	15.8	—
Cash and Cash Equivalents at Beginning of Period	4.6	2.4
Cash and Cash Equivalents at End of Period	$ 20.4	$ 2.4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 72.2	$ 71.6
Net Cash Paid (Received) for Income Taxes	(28.5)	14.9
Cash Paid (Received) for Transferable Tax Credits	(8.7)	(25.4)
Noncash Acquisitions Under Finance Leases	1.8	1.3
Construction Expenditures Included in Current Liabilities as of June 30,	99.3	93.1

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 107.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS OF REGISTRANTS

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

1. SIGNIFICANT ACCOUNTING MATTERS

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

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods for each Registrant. Net income for the three and six months ended June 30, 2025 is not necessarily indicative of results that may be expected for the year ending December 31, 2025. The condensed financial statements are unaudited and should be read in conjunction with the audited 2024 financial statements and notes thereto, which are included in the 2024 Annual Reports.

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 securities. Dilutive securities are primarily related to forward sale of equity agreements and restricted stock units. See Note 13 - Financing Activities for more information regarding the forward sale of equity agreements.

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

	Three Months Ended June 30,			
	2025		2024	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,225.8		$ 340.3	
Weighted-Average Number of Basic AEP Common Shares Outstanding	534.3	$ 2.29	528.9	$ 0.64
Weighted-Average Dilutive Effect	2.1	—	1.2	—
Weighted-Average Number of Diluted AEP Common Shares Outstanding	536.4	$ 2.29	530.1	$ 0.64

	Six Months Ended June 30,			
	2025		2024	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 2,026.0		$ 1,343.4	
Weighted-Average Number of Basic AEP Common Shares Outstanding	533.8	$ 3.80	527.7	$ 2.55
Weighted-Average Dilutive Effect	1.7	(0.02)	1.2	(0.01)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	535.5	$ 3.78	528.9	$ 2.54

There were no antidilutive shares outstanding as of June 30, 2025 and 2024.

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

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

Reconciliation of Cash, Cash Equivalents and Restricted Cash

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

	June 30, 2025			
	AEP	**AEP Texas**	**APCo**	**SWEPCo**
	(in millions)			
Cash and Cash Equivalents	$ 227.3	$ 0.1	$ 6.2	$ 3.7
Restricted Cash	51.3	13.3	18.2	16.7
Total Cash, Cash Equivalents and Restricted Cash	$ 278.6	$ 13.4	$ 24.4	$ 20.4

	December 31, 2024			
	AEP	**AEP Texas**	**APCo**	**SWEPCo**
	(in millions)			
Cash and Cash Equivalents	$ 202.9	$ 0.1	$ 3.9	$ 1.2
Restricted Cash	43.1	23.5	16.2	3.4
Total Cash, Cash Equivalents and Restricted Cash	$ 246.0	$ 23.6	$ 20.1	$ 4.6

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. On March 27, 2025, the SEC announced that it voted to end its defense of the final climate disclosure rules. On April 3, 2025, 18 states filed a motion to intervene in the case and to hold the case in abeyance until the SEC takes action to amend or rescind the rules. The Registrants are currently evaluating the status of the rules and 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 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.

Management adopted ASU 2023-07 and its related implementation guidance effective January 1, 2024 for the annual reporting period and applied the amendments retrospectively to all prior periods presented in the annual consolidated financial statements. The amendments for interim periods were adopted in the fiscal year beginning on January 1, 2025. The adoption of the new standard did not impact the results of operations, statements of financial position or cash flows. See Note 8 - Business Segments for additional information.

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 will adopt the amendments to this standard prospectively beginning with the Annual Report on Form 10-K for the fiscal year ending December 31, 2025.

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 June 30, 2025	Cash Flow Hedges		Pension	
	Commodity	Interest Rate	and OPEB	Total
	(in millions)			
Balance in AOCI as of March 31, 2025	$ 123.7	$ 1.2	$ (104.6)	$ 20.3
Change in Fair Value Recognized in AOCI, Net of Tax	(36.0)	—	—	(36.0)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	4.8	—	—	4.8
Interest Expense (a)	—	(1.2)	—	(1.2)
Amortization of Prior Service Cost (Credit)	—	—	(0.3)	(0.3)
Amortization of Actuarial (Gains) Losses	—	—	0.6	0.6
Reclassifications from AOCI, before Income Tax (Expense) Benefit	4.8	(1.2)	0.3	3.9
Income Tax (Expense) Benefit	1.0	(0.2)	—	0.8
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	3.8	(1.0)	0.3	3.1
Net Current Period Other Comprehensive Income (Loss)	(32.2)	(1.0)	0.3	(32.9)
Balance in AOCI as of June 30, 2025	$ 91.5	$ 0.2	$ (104.3)	$ (12.6)

Three Months Ended June 30, 2024	Cash Flow Hedges		Pension	
	Commodity	Interest Rate	and OPEB	Total
	(in millions)			
Balance in AOCI as of March 31, 2024	$ 87.2	$ 3.4	$ (152.9)	$ (62.3)
Change in Fair Value Recognized in AOCI, Net of Tax	7.0	6.9	—	13.9
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	11.8	—	—	11.8
Interest Expense (a)	—	(1.1)	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	—	(1.3)	(1.3)
Amortization of Actuarial (Gains) Losses	—	—	1.2	1.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	11.8	(1.1)	(0.1)	10.6
Income Tax (Expense) Benefit	2.3	(0.1)	—	2.2
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	9.5	(1.0)	(0.1)	8.4
Net Current Period Other Comprehensive Income (Loss)	16.5	5.9	(0.1)	22.3
Balance in AOCI as of June 30, 2024	$ 103.7	$ 9.3	$ (153.0)	$ (40.0)

Six Months Ended June 30, 2025	Cash Flow Hedges		Pension	
	Commodity	Interest Rate	and OPEB	Total
		(in millions)		
Balance in AOCI as of December 31, 2024	$ 98.5	$ 3.3	$ (104.9)	$ (3.1)
Change in Fair Value Recognized in AOCI, Net of Tax	2.2	(1.0)	—	1.2
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(11.7)	—	—	(11.7)
Interest Expense (a)	—	(2.6)	—	(2.6)
Amortization of Prior Service Cost (Credit)	—	—	(0.4)	(0.4)
Amortization of Actuarial (Gains) Losses	—	—	1.1	1.1
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(11.7)	(2.6)	0.7	(13.6)
Income Tax (Expense) Benefit	(2.5)	(0.5)	0.1	(2.9)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(9.2)	(2.1)	0.6	(10.7)
Net Current Period Other Comprehensive Income (Loss)	(7.0)	(3.1)	0.6	(9.5)
Balance in AOCI as of June 30, 2025	$ 91.5	$ 0.2	$ (104.3)	$ (12.6)

Six Months Ended June 30, 2024	Cash Flow Hedges		Pension	
	Commodity	Interest Rate	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	12.5	19.3	—	31.8
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(17.5)	—	—	(17.5)
Interest Expense (a)	—	(2.3)	—	(2.3)
Amortization of Prior Service Cost (Credit)	—	—	(2.6)	(2.6)
Amortization of Actuarial (Gains) Losses	—	—	1.7	1.7
Reclassifications from AOCI, before Income Tax Expense	(17.5)	(2.3)	(0.9)	(20.7)
Income Tax Expense	(3.8)	(0.4)	(0.2)	(4.4)
Reclassifications from AOCI, Net of Income Tax Expense	(13.7)	(1.9)	(0.7)	(16.3)
Net Current Period Other Comprehensive Income (Loss)	(1.2)	17.4	(0.7)	15.5
Balance in AOCI as of June 30, 2024	$ 103.7	$ 9.3	$ (153.0)	$ (40.0)

(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 2024 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2024 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 2025 and updates the 2024 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 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 requested recovery including a weighted average cost of capital carrying charge in its Arkansas base rate case filed in March 2025. 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 June 30, 2025, the Texas jurisdictional share of the net book value of the Pirkey Plant was $76 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. Following the 2024 Oklahoma Base Rate Case, PSO continues to recover Northeastern Plant, Unit 3 through 2040. In April 2025, PSO and the ODEQ finalized a second amended regional haze agreement that would allow continued operation of the Northeastern Plant, Unit 3, on natural gas, through May 31, 2041. This agreement is contingent upon approval by the Federal EPA in the form of a revised SIP. The ODEQ is in the process of preparing a SIP submission for the Federal EPA's review and approval.

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. In December 2024, SWEPCo filed an application for a Certificate of Convenience and Necessity (CCN) with the APSC, LPSC and PUCT to convert Welsh Plant, Units 1 and 3 to natural gas in 2028 and 2027, respectively.

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of June 30, 2025, 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	$	79.8	$	204.7	$	21.1	(b)	2026		(c)	$	16.7
Welsh Plant, Units 1 and 3		300.9		192.7		57.7	(d)	2028	(e)	(f)		45.9

(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.
(f) Unit 1 is being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Unit 3 is being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

Dolet Hills Power Station and Related Fuel Operations (Applies to AEP and SWEPCo)

In December 2021, the Dolet Hills Power Station was retired. While in operation, DHLC provided 100% of the fuel supply to Dolet Hills Power Station. The remaining book value of Dolet Hills Power Station non-fuel related assets are recoverable by SWEPCo through rate riders. As of June 30, 2025, SWEPCo's share of the net investment in the Dolet Hills Power Station was $70 million, including materials and supplies, net of cost of removal collected in rates. Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses and are subject to prudency determinations by the various commissions. After closure of the DHLC mining operations and the Dolet Hills Power Station, additional reclamation and other land-related costs incurred by DHLC and Oxbow will continue to be billed to SWEPCo and included in existing fuel clauses. As of June 30, 2025, SWEPCo had a net under-recovered fuel balance of $26 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 June 30, 2025, SWEPCo's share of the net investment in the Pirkey Plant was $204 million, including materials and supplies, net of cost of removal. See the "Regulated Generating Units that have been Retired" section above for additional information. Fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions. As of March 31, 2023, SWEPCo fuel deliveries, including billings of all fixed costs, from Sabine ceased. Additionally, as of June 30, 2025, SWEPCo had a net under-recovered fuel balance of $26 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. In April 2025, the LPSC determined the retirement of the Pirkey Plant was reasonable and prudent and authorized continued recovery of and on the remaining balance of the Pirkey Plant at SWEPCo's weighted average cost of capital through 2032.

In September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of $33 million of Sabine related fuel costs through 2035. In June 2024, SWEPCo filed a fuel reconciliation with the PUCT for its retail operation in Texas for the period of January 2022 through December 2023. The fuel reconciliation included approximately $535 million in Texas jurisdictional eligible fuel costs. In January 2025, intervenors filed testimony recommending a disallowance of Texas jurisdictional fuel costs ranging from $2 million to $33 million related to SWEPCo's decision to retire the Pirkey Plant, management of fuel inventory and SWEPCo's energy price offers in SPP. In April 2025, a settlement agreement was filed with the PUCT resolving the issues in the case and resulting in a one-time $6 million disallowance of fuel costs. An order is expected in 2025.

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	
Noncurrent Regulatory Assets	**June 30, 2025**	**December 31, 2024**
	(in millions)	
Regulatory Assets Currently Earning a Return		
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 192.7	$ 168.6
Pirkey Plant Accelerated Depreciation	132.6	121.3
Unrecovered Winter Storm Fuel Costs (a)	55.9	70.7
Storm-Related Costs	53.8	51.0
AEP Texas House Bill 5247	25.0	—
Other Regulatory Assets Pending Final Regulatory Approval	26.5	20.7
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs (b)	378.3	357.4
Storm-Related Costs	310.5	300.8
2024-2025 Virginia Biennial Under-Earnings	156.5	78.4
NOLC Costs (c)	88.8	92.8
Other Regulatory Assets Pending Final Regulatory Approval	107.3	86.3
Total Regulatory Assets Pending Final Regulatory Approval	$ 1,527.9	$ 1,348.0

(a) Includes $37 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of June 30, 2025 and December 31, 2024, respectively. See "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) See "NOLCs in Retail Jurisdictions - IRS PLRs" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

	AEP Texas	
Noncurrent Regulatory Assets	**June 30, 2025**	**December 31, 2024**
	(in millions)	
Regulatory Assets Currently Earning a Return		
Storm-Related Costs	$ 41.3	$ 41.3
AEP Texas House Bill 5247	25.0	—
Other Regulatory Assets Pending Final Regulatory Approval	1.2	—
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	30.9	13.1
Deferred Pension and OPEB Costs	21.7	15.6
Line Inspection Costs	5.8	5.8
Other Regulatory Assets Pending Final Regulatory Approval	1.4	1.3
Total Regulatory Assets Pending Final Regulatory Approval	$ 127.3	$ 77.1

Noncurrent Regulatory Assets	APCo June 30, 2025	APCo December 31, 2024
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 1.3	$ 1.1
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs (a)	299.4	282.1
Storm-Related Costs – West Virginia	163.2	144.2
2024-2025 Virginia Biennial Under-Earnings	156.5	78.4
Pension Settlement	17.1	17.8
Other Regulatory Assets Pending Final Regulatory Approval	20.9	11.9
Total Regulatory Assets Pending Final Regulatory Approval	$ 658.4	$ 535.5

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

Noncurrent Regulatory Assets	I&M June 30, 2025	I&M December 31, 2024
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 6.7	$ 6.4
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs (a)	76.2	74.0
Storm-Related Costs – Indiana	24.0	6.3
NOLC Costs – Indiana (b)	—	26.7
Other Regulatory Assets Pending Final Regulatory Approval	1.9	1.6
Total Regulatory Assets Pending Final Regulatory Approval	$ 108.8	$ 115.0

(a) See "Federal EPA's Revised CCR Rule" section of Note 5 for additional information.
(b) See "NOLCs in Retail Jurisdictions - IRS PLRs" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

Noncurrent Regulatory Assets	OPCo June 30, 2025	OPCo December 31, 2024
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 0.7	$ 0.4
Regulatory Assets Currently Not Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	—	0.1
Total Regulatory Assets Pending Final Regulatory Approval	$ 0.7	$ 0.5

Noncurrent Regulatory Assets	PSO June 30, 2025	PSO December 31, 2024
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
NOLC Costs (a)	$ 23.2	$ 16.4
Storm-Related Costs	21.3	4.9
Pension Settlement	7.5	7.8
Other Regulatory Assets Pending Final Regulatory Approval	9.5	1.2
Total Regulatory Assets Pending Final Regulatory Approval	**$ 61.5**	**$ 30.3**

(a) See "NOLCs in Retail Jurisdictions - IRS PLRs" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

Noncurrent Regulatory Assets	SWEPCo June 30, 2025	SWEPCo December 31, 2024
	(in millions)	
Regulatory Assets Currently Earning a Return		
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 192.7	$ 168.6
Pirkey Plant Accelerated Depreciation	132.6	121.3
Unrecovered Winter Storm Fuel Costs (a)	55.9	70.7
Dolet Hills Power Station Accelerated Depreciation (b)	12.0	11.8
Other Regulatory Assets Pending Final Regulatory Approval	17.1	10.8
Regulatory Assets Currently Not Earning a Return		
NOLC Costs (c)	65.6	49.6
Storm-Related Costs - Louisiana, Texas	45.9	39.9
Other Regulatory Assets Pending Final Regulatory Approval	18.7	18.7
Total Regulatory Assets Pending Final Regulatory Approval	**$ 540.5**	**$ 491.4**

(a) Includes $37 million of unrecovered winter storm fuel costs recorded as a current regulatory asset as of June 30, 2025 and December 31, 2024, respectively. See "February 2021 Severe Winter Weather Impacts in SPP" section below for additional information.
(b) Amounts include the FERC jurisdiction.
(c) See "NOLCs in Retail Jurisdictions - IRS PLRs" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

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

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

AEP Texas Interim Transmission and Distribution Rates

Through June 30, 2025, AEP Texas' cumulative revenues from transmission and distribution interim base rate increases that are subject to review are estimated to be approximately $43 million. A base rate review could result in a refund to customers if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition.

Texas Legislation

On June 20, 2025, Texas House Bill 5247 (HB 5247) was signed into law by the Governor of Texas and became effective. The bill establishes a tracking mechanism for qualifying electric utilities to file annual interim rate adjustments for cost recovery of certain transmission and distribution capital expenditures. On June 27, 2025, AEP Texas filed with the PUCT notice of qualification and election to follow the new methodology as permitted by HB 5247. Qualifying electric utilities under HB 5247 consist of utilities that: (a) operate solely in ERCOT, (b) have been identified by the PUCT as having responsibility for constructing transmission infrastructure as part of ERCOT's Permian Basin Reliability Plan and (c) make annual capital expenditures in transmission and distribution that exceed 300% of annual depreciation. Based on those requirements, AEP Texas is a qualifying electric utility and SWEPCo and ETT are not qualifying electric utilities.

The tracking mechanism permits a qualifying electric utility to defer all or a portion of costs associated with its eligible transmission and distribution capital investments, including depreciation expense and carrying costs, as a regulatory asset. The tracking mechanism is available through 2035 and is an alternative to the existing capital tracking mechanisms in Texas. Deferred costs will be recovered through interim rate updates over a period not to exceed 18 months and earn a return until recovered. As a result of the new legislation, AEP Texas deferred approximately $25 million of eligible costs through June 2025 as a regulatory asset. Investments included in the tracking mechanism and the existing capital tracker filings remain subject to prudency review in the utility's next base rate review before the PUCT. If any of these deferred costs are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

<u>APCo and WPCo Rate Matters</u> (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 (WVSC) to initiate an appeal of the January 2024 order. Following arguments that were held in September 2024, the WVSC issued a November 2024 opinion affirming in part and reversing in part the WVPSC's January 2024 ENEC order. The WVSC remanded the ENEC case to the WVPSC to afford the Companies an opportunity to examine, analyze, rebut and refute the calculation of the $232 million disallowance. In March 2025, the WVPSC entered an order in the Companies' 2021-2023 ENEC cases further describing its calculations of the ordered $232 million disallowance. In June 2025, the Companies submitted direct testimony on remand supporting a reduction to the WVPSC's previously-ordered disallowance of at least $179 million. Staff and intervenor testimony is due in August 2025 and a hearing is scheduled for October 2025.

In April 2024, the Companies submitted their 2024 ENEC update case 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 August 2024, the WVPSC issued an order approving the requested $38 million annual increase effective September 1, 2024. In March 2025, the WVPSC issued an order approving the requested $20 million annual increase effective March 11, 2025.

In April 2025, the Companies submitted their 2025 ENEC update filing proposing a $72 million annual increase in ENEC rates. In July 2025, WVPSC staff and intervenors filed testimony, and one intervening party recommended a disallowance of approximately $19 million.

If any ENEC 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 SCC 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 part of APCo’s 2024 fuel cost filing.

In September 2024, APCo submitted its annual Virginia fuel cost filing with the Virginia SCC proposing no change in annual APCo Virginia FAC rates charged to customers. In January 2025, an intervening party recommended a minimum fuel under-recovery disallowance of $20 million related to alleged imprudent operations of Amos and Mountaineer generating units during October 2021 and November 2021. There were no other recommended disallowances by intervenors or Virginia Staff regarding APCo’s historical period Virginia fuel under-recovery balance through October 31, 2024. Virginia Staff recommended that the Virginia SCC close APCo’s open review periods related to 2021 and 2022 Virginia fuel costs. A hearing was held in February 2025. In March 2025, the Hearing Examiner re-opened the record to obtain additional information to resolve certain issues. In April 2025, APCo and an intervenor submitted supplemental testimony with the intervenor continuing to recommend a $20 million disallowance. A hearing was held in May 2025. In June 2025, the Hearing Examiner issued a report recommending no disallowance. An order is anticipated from the Virginia SCC in the third quarter of 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.

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 expenses over a three-year period plus a carrying charge on the deferral balance, 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. Securitization of those items could reduce the Companies’ combined requested increase in annual base rates to $37 million. See the “2025 West Virginia Securitization Filing” section below for additional information.

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.

In April 2025, a hearing was held at the WVPSC to review the Companies' separate depreciation filing. Also in April 2025, WVPSC staff and intervenors submitted testimony regarding the Companies' base rate filing recommending combined APCo and WPCo base rate increases ranging from $49 million to $91 million based on proposed ROEs ranging from 9.1% to 9.25%. In May 2025, the combined APCo and WPCo base rate increases range was revised to $49 million to $72 million. These base rate recommendations included significant decreases in rate base for the use of a 13-month average rate base rather than a year-end rate base as proposed by the Companies, and also included various reductions to the Companies' proposed ongoing levels of depreciation expense and other operation and maintenance expenses. WVPSC staff recommended that the WVPSC approve the Companies' requested recovery of $118 million of deferred extraordinary storm costs over a five-year period rather than the proposed three-year recovery period, while also recommending that the WVPSC reject the Companies' proposal of a carrying charge on the storm deferral balance if the recovery is more than three years. WVPSC staff and an intervenor also recommended that the WVPSC deny the ratemaking impact of NOLC and reject the Companies' request to continue the MRBC surcharge. In May 2025, the Companies filed rebuttal testimony supporting a net $224 million annual increase in base rates. A hearing was held at the WVPSC in June 2025 and an order is expected in the third quarter of 2025.

For the Companies' first proposed alternative ratemaking framework described above, WVPSC staff and intervenors recommended that the WVPSC: a) consider securitization subject to certain conditions, b) approve the Companies' proposed major storm deferral accounting for major storm other operation and maintenance expenses against the level embedded in the development of base rates, and c) reject the proposed freeze of OATT revenues in the ENEC. WVPSC staff and intervenors generally recommended that the WVPSC reject the Companies' second proposed alternative ratemaking framework described above.

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. In July 2025, the WVPSC issued an order stating that a ruling on the Companies' 2024 MRBC surcharge update filing and all contested issues will be included in the August 2025 order on the Companies' 2024 West Virginia base case filing. If any refund liabilities are imposed by the WVPSC, it could reduce future net income and cash flows and impact financial condition.

2025 West Virginia Securitization Filing

In March 2025, APCo and WPCo (the Companies) requested to finance, through the issuance of securitization bonds, approximately $2.4 billion of West Virginia jurisdictional undepreciated property balances and regulatory assets including: (a) $321 million of the Companies' remaining combined unrecovered ENEC balance related to costs incurred through February 28, 2023, (b) $1.7 billion of undepreciated West Virginia jurisdictional plant balances as of December 31, 2022 for the Amos, Mitchell and Mountaineer Plants, (c) $237 million of environmental costs previously approved for recovery through a separate West Virginia surcharge and (d) $118 million of West Virginia jurisdictional major storm operation and maintenance costs deferred as of June 2024. The proposed securitized items breakout for the Companies is shown in the table below:

Proposed Securitized Items	APCo	WPCo	Total
		(in millions)	
Undepreciated Utility Plant Balances of Amos, Mitchell and Mountaineer (as of December 31, 2022)	$ 1,145.5	$ 558.7	$ 1,704.2
ENEC Under-Recovery Regulatory Assets (as of February 28, 2023)	174.3	146.8	321.1
Forecasted Undepreciated CCR and ELG Investments of Amos, Mitchell and Mountaineer (as of November 30, 2024)	87.6	149.2	236.8
Deferred Storm O&M Expense Regulatory Assets (as of June 30, 2024)	115.0	2.9	117.9
Upfront Financing Costs	10.1	5.7	15.8
Total	$ 1,532.5	$ 863.3	$ 2,395.8

The Companies also proposed that the WVPSC consider approving the securitization of additional ENEC under-recovered costs, such as those costs approved in the 2024 ENEC case, as well as additional deferred West Virginia jurisdictional major storm operation and maintenance costs, such as those associated with Hurricane Helene and Winter Storms Blair, Harlow and Jett.

In May 2025, WVPSC staff recommended that the $321 million ENEC under-recovery and $118 million storm cost deferral be excluded from the securitization. Staff recommended that the $321 million ENEC under-recovery continue to be recovered through the current ENEC rates and the storm cost deferral be recovered without a carrying charge over five years through base rates to be implemented in August 2025. A hearing was held in July 2025 and an order is expected in the third quarter of 2025.

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

2025 Virginia Securitization Filing

In July 2025, APCo filed a request with the Virginia SCC to finance, through the issuance of securitization bonds, approximately $1.4 billion of Virginia jurisdictional undepreciated property balances and a major storm operation and maintenance regulatory asset deferral balance. This proposed securitization included: (a) $1.2 billion of undepreciated Virginia jurisdictional plant balances as of December 31, 2023 for the Amos and Mountaineer Plants and (b) $141 million of Virginia jurisdictional major storm other operation and maintenance expenses deferred during the 2024-2025 biennial period.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT’s revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next base rate proceeding. Through June 30, 2025, AEP’s share of ETT’s cumulative revenues from interim base rate increases that are subject to a prudency review is approximately $1.9 billion. The 2025 ETT base rate case described below could result in a refund to customers if ETT incurs a disallowance of the transmission investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition.

2025 ETT Base Rate Case

In January 2025, ETT filed a request with the PUCT for a $57 million annual base rate increase over its adjusted test year revenues which includes interim transmission rate updates. ETT’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 review determination on cumulative capital additions included in interim rates. In April and May 2025, respectively, intervenors and PUCT staff submitted testimony challenging components of the proposed rate increase including up to $37 million related to increased depreciation rates and $32 million related to the proposed ROE and capital structure.

In June 2025, a unanimous and unopposed settlement was filed with the PUCT along with a motion to approve interim rates, equal to the rates specified in the settlement, effective on June 20, 2025. The settlement terms include a base rate increase of approximately $20 million, based on an ROE of 9.6% and a capital structure of 59% debt and 41% equity. The settlement also includes a determination that ETT’s invested capital and rate base are prudent and properly included in rates. The motion to approve interim rates was granted in June 2025 and the settlement is subject to approval by the PUCT. If any of the costs in the case are not recoverable or revenues collected under interim transmission rates are ordered to be returned, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters (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 (ICPA) and the Rockport UPA with AEGCo ranging from $3 million to $15 million. In July 2025, the MPSC issued an order resulting in a combined $3 million PSCR cost disallowance related to OVEC and Rockport UPA costs. In July 2025, the IURC issued an order on I&M’s Resource Adequacy Rider update filing approving I&M’s proposed capacity resource adjustments, including prospective recovery of OVEC capacity, energy and associated costs that were previously assigned to I&M Michigan retail customers starting with the June 2025-May 2026 PJM delivery year.

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. Management believes its financial statements adequately address the impact of the Indiana earnings test requirements. If future IURC orders require that I&M provide credits in the FAC factor computation, it could reduce future net income and cash flows and impact financial condition.

In January 2025, I&M submitted its FAC filing and earnings test evaluation for the period ended November 2024. I&M proposed an over-earnings credit to customers for the earnings test period ending November 2024 of $21 million. In April 2025, the IURC issued an order approving the $21 million customer credit.

<u>KPCo Rate Matters</u> (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 future 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. See "Mitchell Plant Filing for Certificate of Public Convenience and Necessity" section below for additional information.

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 (Circuit Court), challenging among other aspects of the order, the $14 million base rate revenue requirement reduction. In January 2025, the Circuit Court issued an order agreeing with KPCo's appeal and remanded this issue back to the KPSC with instructions to enter an order, within 30 days, which includes setting rates to allow KPCo to recover the $14 million of annual PJM transmission costs effective upon KPCo's January 2024 implementation of updated base rates. In March 2025, the KPSC issued a rehearing order that approved rates for the prospective collection of test year PJM transmission costs beginning in February 2025 but denied KPCo's request to defer and recover the historical PJM transmission costs of approximately $16 million incurred since January 2024. In April 2025, KPCo filed an appeal with the Circuit Court in response to the KPSC's denial to recover PJM transmission costs incurred from January 2024 through the implementation of new rates. A Circuit Court ruling is expected in the second half of 2025.

In June 2025, KPCo issued $478 million of securitization bonds to recover $500 million of regulatory assets, including $311 million of plant retirement costs, $79 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, $56 million of under-recovered purchased power rider costs, $51 million of deferred purchased power expenses and $3 million of issuance-related expenses, including KPSC advisor expenses. The net bond proceeds of $478 million also included $6 million for non-utility issuance costs and a $29 million offset for net present value of return on accumulated deferred income taxes related to KPCo's Decommissioning Rider as ordered by the KPSC.

Mitchell Plant Filing for Certificate of Public Convenience and Necessity

KPCo and WPCo each currently hold a 50% ownership interest in the Mitchell Plant and related CCR investments that have been placed in service. In July 2021, the KPSC rejected KPCo's ELG compliance plan for KPCo's 50% ownership share of ELG investments at the Mitchell Plant that would allow KPCo to take capacity and energy to serve customers beyond December 31, 2028. As a result of this order, WPCo holds a 100% interest in Mitchell Plant ELG investments that have been placed in service. In addition, WPCo also holds a greater than 50% ownership share of certain non-ELG capital investments made at Mitchell Plant which will continue to be used in the operation of Mitchell Plant beyond 2028.

In June 2025, KPCo filed a request with the KPSC for a Certificate of Public Convenience and Necessity (CPCN) to make investments necessary to reflect: (a) a 50% share of the Mitchell Plant ELG Project and (b) a 50% share of non-ELG capital investments. KPSC approval of these investments would allow KPCo to continue taking a 50% share of energy and capacity from the Mitchell Plant to serve KPCo customers beyond December 31, 2028. KPCo proposed to recover the estimated $78 million investment in the ELG Project through KPCo's existing Environmental Surcharge and plans to request recovery of an estimated $60 million of Mitchell Plant non-ELG capital investments through a future base rate filing.

As of June 30, 2025, the net book value of KPCo's share of the Mitchell Plant, before cost of removal and including CWIP and inventory, was $535 million.

If any costs related to this CPCN filing are disallowed, 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. In December 2024, intervenors filed appeals with the Supreme Court of Ohio on the PUCO's denial for rehearing.

In February and March 2025, as part of OVEC cost recovery audits pending before the PUCO, intervenors filed positions claiming that costs incurred by OPCo during the 2021-2023 audit period were imprudent and should be disallowed. Management disagrees with these claims and is unable to predict the impact of these disputes. If any costs are disallowed or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

Ohio Legislation (HB 15)

Ohio House Bill 15 (HB 15) was approved by the Ohio legislature in April 2025 and signed into law by the Governor of Ohio in May 2025. HB 15 is effective beginning August 14, 2025 and (a) alters rate-setting mechanisms by replacing ESPs with triennial base rate cases based on a three-year forecasted test period, effective with the end of OPCo's previously approved ESP which ends in May 2028, (b) eliminates OPCo's ability to recover from, or refund to, customers the difference between purchased power expenses from OVEC and the market revenues OPCo receives from that purchased power as of the effective date of the law and (c) repeals the statute that permits electric distribution utilities, including OPCo, to execute contracts to provide customer-sited renewable generation service such as fuel cell technology or other renewable resources prospectively.

As a result of this legislation, in the first quarter of 2025, OPCo recorded a $35 million estimated reduction to its OVEC-related purchased power regulatory asset for deferred net costs that are no longer probable of future recovery. Management is unable to predict the future impact to net income, cash flows and financial condition arising from the future changes in OPCo's rate setting mechanisms and the elimination of OPCo's ability to recover from, or refund to, customers the difference between purchased power expenses from OVEC and the market revenues OPCo receives from that purchased power.

2025 Ohio Base Rate Case

In May 2025, OPCo filed a request with the PUCO for a net $97 million annual increase in distribution base rates based upon a 10.9% ROE and a proposed capital structure of 49.1% debt and 50.9% common equity. The requested net annual increase in base rates excluded $308 million of existing annual rider revenue requirements (including the Distribution Investment Rider (DIR)) that OPCo proposed to be rolled into base rates upon the anticipated 2026 change in distribution base rates in this filing. The distribution base case filing also requests a revenue cap increase for the DIR and cost cap increase for OPCo's existing Enhanced Service Reliability Rider. 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.

PSO Rate Matters (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 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.

In January 2025, the OCC issued a final order approving the joint stipulation and settlement agreement without modification. In February 2025, an Oklahoma state representative filed an appeal of the final order in PSO's base rate case. The appeal does not contest the reasonableness of the rates established under the joint stipulation and settlement agreement approved without modification in the final order, but rather raises issues related to one OCC commissioner's participation in voting on the order and the sufficiency of an OCC audit. If the appeal is successful and the OCC modifies the final order in a future proceeding, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters (Applies to AEP and SWEPCo)

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.

February 2021 Severe Winter Weather Impacts in SPP

In February 2021, severe winter weather had a significant impact in SPP, resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. For the time period of February 9, 2021 to February 20, 2021, SWEPCo's natural gas expenses and purchases of electricity still to be recovered from customers are shown in the table below:

Jurisdiction	June 30, 2025	December 31, 2024	Approved Recovery Period	Approved Carrying Charge
	(in millions)			
Arkansas	$ 29.6	$ 37.2	6 years	(a)
Louisiana	55.9	70.6	(b)	(b)
Texas	58.5	72.7	5 years	1.65%
Total	$ 144.0	$ 180.5		

(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.

2025 Arkansas Base Rate Case

In March 2025, SWEPCo filed a request with the APSC for a $114 million annual base rate increase based upon a 10.9% ROE with a capital structure of 52.3% debt and 47.7% common equity. The increase includes the Arkansas jurisdictional share of Diversion and Wagon Wheel wind facilities. SWEPCo is also electing to have its rates regulated under a Formula Rate Review mechanism. APSC staff and intervenor testimony is due in August 2025 and a hearing is scheduled for November 2025. 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.

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

North Central Wind Energy Facilities (NCWF)

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 experienced performance issues that prompted PSO and SWEPCo to file a lawsuit against the manufacturer, which led to an agreement between PSO and SWEPCo and the manufacturer that addressed the performance issues. If regulatory performance requirements, such as the NCF guarantee, are not met, PSO and SWEPCo may recognize a regulatory liability associated with a refund to 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 (MPSC) approved a Certificate of Public Convenience and Necessity (CPCN) 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, which is currently pending and awaiting decision. Additional regulatory proceedings before the PAPUC are expected to resume in 2025 or 2026. In June 2025, the MPSC gave notice that it extended a temporary extension of the construction commencement deadline until the MPSC can further consider the matter at an administrative meeting.

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 canceled and remains necessary to alleviate congestion. PJM continues to evaluate reliability and market efficiency in the area. As of June 30, 2025, AEP's share of IEC capital expenditures was approximately $91 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 canceled for reasons outside the control of Transource Energy. If any of the IEC costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge (Applies to all Registrant Subsidiaries except AEP Texas)

The Registrants transitioned to stand-alone treatment of NOLCs in their 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. The annual revenue requirement increase as a result of the transition to stand-alone treatment of NOLCs for transmission formula rates is shown in the table below:

2021	2022	2023	2024	2025	Total
		(in millions)			
$ 78.3	$ 68.5	$ 60.7	$ 52.1	$ 48.7	$ 308.3

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, AEP transmission owning subsidiaries within PJM and SPP are providing refunds for the 2021 rate year, primarily through 2025 projected transmission revenue requirements. AEP transmission owning subsidiaries within PJM and SPP have not been directed to make cash refunds related to 2022 through 2025 rate years. As a result of the January 2024 FERC orders, the Registrants' balance sheets reflected a liability for the probable refund of all NOLC revenues included in transmission formula rates, with interest.

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 requested 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 its initial orders.

In June 2025, the FERC issued two orders, partially reversing its January 2024 decisions on the basis of IRS PLRs accepted into the record, and concluding that the accelerated depreciation-related NOLC adjustments should be included in rate base and should also be included in the computation of Excess ADIT regulatory liabilities to be refunded to customers. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to submit compliance filings in August 2025 that will revise March 2024 refund compliance reports and permit the collection of excess refunds provided to customers, with interest, in the annual update for the 2025 rate year.

As a result of the June 2025 FERC orders, the Registrants recognized revenues, with interest, attributable to accelerated depreciation-related NOLCs included in transmission formula rates for years 2021 through 2025 and reduced Excess ADIT regulatory liabilities. Increases in affiliated transmission expense, which correspond to affiliated transmission revenues recognized, were deferred as an increase to regulatory assets or a reduction to regulatory liabilities on the balance sheets where management expects that expense would be collected from retail customers through authorized retail jurisdiction rider mechanisms. The table below summarizes the impact to the statements of income recorded by the Registrants in the second quarter of 2025:

	AEP	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Total Revenues	$ 270.5	$ 214.3	$ 5.6	$ 10.8	$ —	$ 6.4	$ 26.9
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(23.9)	—	(17.2)	—	—	—	—
Other Operation	53.0	—	14.8	(6.0)	0.1	18.8	10.1
Income (Loss) Before Income Tax Expense (Benefit)	241.4	214.3	8.0	16.8	(0.1)	(12.4)	16.8
Income Tax Expense (Benefit)	(312.8)	(203.2)	(21.4)	(27.8)	—	(15.6)	(38.9)
Net Income (Loss)	554.2	417.5	29.4	44.6	(0.1)	3.2	55.7
Net Income Attributable to Noncontrolling Interest	55.2	55.2	—	—	—	—	—
Earnings (Loss) Attributable to Common Shareholder	$ 499.0	$ 362.3	$ 29.4	$ 44.6	$ (0.1)	$ 3.2	$ 55.7

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, or refunds of revenues collected under interim rates are ordered to be returned, it could reduce future net income and cash flows and impact financial condition.

Transmission Agreement Cost Allocation Complaint (Applies to AEP, APCo, I&M and OPCo)

In March 2025, the KPSC and the Attorney General of Kentucky filed a complaint at the FERC against AEPSC and the AEP East Companies challenging the manner in which costs are allocated for local transmission projects pursuant to the TA. The complaint contends that certain costs allocated to KPCo are unjust, unreasonable and provide no benefit to KPCo customers. The relief requested in the complaint includes requiring a revision to the TA so that the costs for local transmission projects remain exclusively with the retail distribution service territory where the project is located unless a specific project is granted approval to establish a different cost allocation by the state commissions. Various parties have filed comments and motions to intervene. In May 2025, AEP filed a motion to dismiss and answered the complaint. If the FERC orders a change in the way costs are allocated pursuant to the TA it could impact future net income, cash flows and 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 2024 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)

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

AEP has $5 billion and $1 billion revolving credit facilities due in March 2029 and March 2027, respectively. AEP may issue up to $1.2 billion as letters of credit under these revolving credit facilities on behalf of subsidiaries. As of June 30, 2025, 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 June 30, 2025 were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 360.8	July 2025 to July 2026

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of June 30, 2025, 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 June 30, 2025, 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	$ 38.4
AEP Texas	8.3
APCo	5.2
I&M	3.9
OPCo	6.5
PSO	3.5
SWEPCo	4.3

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 (Legacy 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 Legacy 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. 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, based on initial cost estimates primarily reflecting compliance with the rule through closure in place and future groundwater monitoring requirements pursuant to the Legacy CCR Rule.

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 Legacy CCR Rule with the U.S. Court of Appeals for the D.C. Circuit. One of the parties also filed a motion to stay the Legacy CCR Rule pending the outcome of the litigation. In November 2024, the court denied the stay motion. The litigation is being held in abeyance until August 11, 2025. The Federal EPA informed the court that it has determined it will reconsider the Legacy CCR Rule in whole or in part, but has not yet decided the full scope of reconsideration. The Federal EPA expects to have determined which aspects of the Legacy CCR Rule it will reconsider, in whole or in part, by August 11, 2025. Reconsideration of the rule will require a new round of notice-and-comment rulemaking. In July 2025, the Federal EPA issued a direct final rule and companion proposed rule that extended certain compliance deadlines for CCR management units under the Legacy CCR Rule. Management cannot predict the outcome of the litigation or any further actions by the Federal EPA related to the rule.

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 has started the application process for license extensions for both units that would extend Unit 1 and Unit 2 to 2054 and 2057, respectively. 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.

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, 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 the ratemaking process, could reduce future net income and cash flows and impact financial condition.

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 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. Based on the information currently available, management does not believe a loss is probable and cannot determine a range of potential losses, if any, that is reasonably possible of occurring.

6. ACQUISITIONS AND DISPOSITIONS

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

ACQUISITIONS

Green Country Power Plant, Pixley Solar Energy Facility and Flat Ridge IV Wind Energy Facility (Vertically Integrated Utilities Segment) (Applies to AEP and PSO)

In the second quarter of 2025, PSO expanded its generation portfolio by acquiring three electric generation facilities for a total of $1.4 billion. In May 2025, PSO acquired 100% of the equity interests in Pixley Solar Energy, LLC, the owner of the newly constructed Pixley solar energy facility in Barber County, Kansas. The Pixley facility, placed in service in May 2025, serves both FERC and retail customers in Oklahoma. PSO's revenue requirement is recoverable through an authorized rider until it is incorporated into base rates. Regulatory approval of Pixley's output in retail rates included capital cost, performance and other guarantees, which may subject PSO to future regulatory liabilities. In June 2025, PSO also acquired 100% of the equity interests in Flat Ridge IV Wind, LLC, the owner of the newly constructed Flat Ridge IV Wind Energy Facility located in Kingman and Harper Counties, Kansas. This facility, also placed in service in June 2025, serves both FERC and retail customers under similar recovery and regulatory provisions as the Pixley facility. The acquisitions of Pixley and Flat Ridge IV also resulted in the recognition of operating leases for easement and access rights to the land on which the facilities are located, as well as the associated AROs. In accordance with the guidance for "Business Combinations," management determined the acquisitions of Pixley and Flat Ridge IV represent asset acquisitions.

Additionally, in June 2025, PSO completed the acquisition of 100% of the equity interests in Green Country Energy, LLC, the owner of a combined-cycle natural gas facility located in Jenks, Oklahoma, following approvals from both the FERC and the OCC. The transaction included the acquisition of a previously executed capacity sales agreement between Green Country Energy, LLC, as seller, and SWEPCo, as purchaser. As a result, beginning in July 2025, PSO will sell a portion of the Green Country's capacity to SWEPCo through May 2027, the end of the agreement's term. The acquisition also resulted in the extinguishment of a previously executed capacity sales agreement between Green Country Energy, LLC, as seller, and PSO, as purchaser.

In accordance with the guidance for "Business Combinations," management determined the acquisition of Green Country represents an asset acquisition. Asset acquisitions are accounted for using a cost accumulation model, with the cost of the acquisition allocated to the acquired assets and assumed liabilities based on their relative fair value. Upon closing of the transaction, PSO recognized Property, Plant and Equipment of $819 million, an intangible liability of $41 million for the fair value of the acquired SWEPCo capacity sales agreement and a regulatory liability of $50 million, reflective of the recognition and subsequent deferral of the gain from PSO's extinguished capacity sales agreement. The liabilities recognized for the capacity sales agreements will reduce PSO's revenue requirement to recover its overall investment in Green Country, which is recoverable through a rider authorized by the OCC until it is included in base rates for the depreciable life of the facility. AEP management elected the income approach for its nonrecurring valuation of both the intangible liability and regulatory liability. Specifically, management applied a discounted cash flow model based on a forward market price assumption.

The table below summarizes the impact of the acquisitions on PSO's balance sheet as of June 30, 2025:

Plant Name	State	Fuel Type	Generation Capacity (MWs)	Property, Plant and Equipment, Net	Operating Lease Assets	Asset Retirement Obligations	Other Liabilities	
					(in millions)			
Green Country	OK	Natural Gas	795	$ 818.9	$ —	$ —	$ 91.4	(a)
Pixley	KS	Solar	189	379.6	8.9	12.4	—	
Flat Ridge IV	KS	Wind	135	305.3	7.4	3.1	—	
Total			1,119	$ 1,503.8	$ 16.3	$ 15.5	$ 91.4	

(a) $50 million included in Regulatory Liabilities and Deferred Investment Tax Credits, $21 million included in Other Current Liabilities and $20 million included in Deferred Credits and Other Noncurrent Liabilities on PSO's balance sheets.

DISPOSITIONS

Noncontrolling Interest in OHTCo and IMTCo (AEP Transmission Holdco Segment) (Applies to AEP and AEPTCo)

In January 2025, AEP announced a partnership whereby nonaffiliated entities will acquire a 19.9% noncontrolling interest in OHTCo and IMTCo. The partnership was structured pursuant to a contribution agreement between AEPTCo, along with Midwest Transmission Holding Company LLC ("Midwest Transmission"), a wholly-owned subsidiary of AEPTCo that owns all the stock of OHTCo and IMTCo, and Olympus BidCo L.P. ("the Investor"), a special purpose entity controlled by (i) investment funds managed by or affiliated with Kohlberg Kravis Roberts & Co. L.P. and (ii) Public Sector Pension Investment Board, whereby the Investor agreed to acquire a 19.9% noncontrolling equity interest in Midwest Transmission for $2.82 billion. The transaction closed in June 2025. AEP received cash proceeds of approximately $2.78 billion, net of transaction costs. Net proceeds will be used to help finance AEP's $54 billion capital plan for 2025-2029, announced in November 2024, driven by transmission and distribution infrastructure upgrades and new generation to support anticipated load growth.

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 June 30, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 23.9	$ 2.2	$ 2.2	$ 3.1	$ 2.3	$ 1.6	$ 1.9
Interest Cost	52.8	4.3	6.3	6.2	4.8	2.5	3.0
Expected Return on Plan Assets	(70.2)	(5.5)	(9.4)	(9.7)	(7.4)	(3.8)	(3.6)
Amortization of Net Actuarial Loss	4.0	0.4	0.5	0.5	0.4	0.1	0.3
Net Periodic Benefit Cost (Credit)	$ 10.5	$ 1.4	$ (0.4)	$ 0.1	$ 0.1	$ 0.4	$ 1.6

Three Months Ended June 30, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 25.6	$ 2.2	$ 2.5	$ 3.3	$ 2.3	$ 1.6	$ 2.1
Interest Cost	51.9	4.4	6.2	5.9	4.7	2.5	3.1
Expected Return on Plan Assets	(80.2)	(6.6)	(10.7)	(10.6)	(8.1)	(4.4)	(4.4)
Amortization of Net Actuarial Loss	1.1	0.1	0.1	0.1	—	0.1	—
Net Periodic Benefit Cost (Credit) (a)	$ (1.6)	$ 0.1	$ (1.9)	$ (1.3)	$ (1.1)	$ (0.2)	$ 0.8

Six Months Ended June 30, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 47.9	$ 4.4	$ 4.6	$ 6.3	$ 4.6	$ 3.0	$ 3.8
Interest Cost	105.6	8.8	12.5	12.4	9.7	5.2	6.2
Expected Return on Plan Assets	(140.5)	(11.1)	(18.8)	(19.4)	(14.7)	(7.7)	(7.3)
Amortization of Net Actuarial Loss	8.1	0.7	0.9	0.9	0.7	0.3	0.5
Net Periodic Benefit Cost (Credit)	$ 21.1	$ 2.8	$ (0.8)	$ 0.2	$ 0.3	$ 0.8	$ 3.2

Six Months Ended June 30, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 51.2	$ 4.4	$ 4.9	$ 6.6	$ 4.7	$ 3.1	$ 4.0
Interest Cost	103.8	8.7	12.4	11.9	9.4	5.0	6.2
Expected Return on Plan Assets	(160.4)	(13.0)	(21.4)	(21.4)	(16.3)	(8.7)	(8.8)
Amortization of Net Actuarial Loss	2.2	0.2	0.2	0.2	0.1	0.1	0.1
Net Periodic Benefit Cost (Credit) (a)	$ (3.2)	$ 0.3	$ (3.9)	$ (2.7)	$ (2.1)	$ (0.5)	$ 1.5

(a) Excludes an immaterial settlement amount to a non-qualified pension plan in the second quarter of 2024 for AEP. See Note 12 - Voluntary Severance Program for additional information.

OPEB

Three Months Ended June 30, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1.0	$ 0.1	$ 0.2	$ 0.2	$ 0.1	$ 0.1	$ —
Interest Cost	8.6	0.7	1.3	0.9	0.9	0.5	0.6
Expected Return on Plan Assets	(28.3)	(2.4)	(4.1)	(3.3)	(3.0)	(1.5)	(1.9)
Amortization of Prior Service Credit	(0.6)	(0.1)	(0.1)	(0.1)	—	(0.1)	(0.1)
Amortization of Net Actuarial Gain	(0.3)	—	(0.1)	—	—	—	—
Net Periodic Benefit Credit	$ (19.6)	$ (1.7)	$ (2.8)	$ (2.3)	$ (2.0)	$ (1.0)	$ (1.4)

Three Months Ended June 30, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1.1	$ 0.1	$ 0.1	$ 0.2	$ 0.1	$ —	$ 0.1
Interest Cost	10.6	0.8	1.6	1.2	1.0	0.6	0.6
Expected Return on Plan Assets	(27.9)	(2.2)	(4.1)	(3.3)	(2.9)	(1.6)	(1.8)
Amortization of Prior Service Credit	(3.2)	(0.2)	(0.4)	(0.5)	(0.3)	(0.2)	(0.2)
Amortization of Net Actuarial Loss	0.7	—	0.1	0.1	0.1	0.1	—
Net Periodic Benefit Credit (a)	$ (18.7)	$ (1.5)	$ (2.7)	$ (2.3)	$ (2.0)	$ (1.1)	$ (1.3)

Six Months Ended June 30, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1.8	$ 0.2	$ 0.3	$ 0.3	$ 0.2	$ 0.1	$ 0.1
Interest Cost	17.2	1.3	2.7	1.9	1.7	0.9	1.1
Expected Return on Plan Assets	(56.5)	(4.7)	(8.2)	(6.7)	(5.9)	(3.0)	(3.8)
Amortization of Prior Service Credit	(1.2)	(0.1)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)
Amortization of Net Actuarial Gain	(0.6)	—	(0.2)	—	—	—	—
Net Periodic Benefit Credit	$ (39.3)	$ (3.3)	$ (5.6)	$ (4.7)	$ (4.1)	$ (2.1)	$ (2.7)

Six Months Ended June 30, 2024	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 2.2	$ 0.2	$ 0.2	$ 0.3	$ 0.2	$ 0.1	$ 0.2
Interest Cost	21.1	1.6	3.3	2.4	2.1	1.1	1.3
Expected Return on Plan Assets	(55.7)	(4.5)	(8.1)	(6.7)	(5.9)	(3.0)	(3.7)
Amortization of Prior Service Credit	(6.4)	(0.5)	(0.9)	(0.9)	(0.6)	(0.4)	(0.5)
Amortization of Net Actuarial Loss	1.5	0.1	0.2	0.2	0.2	0.1	0.1
Net Periodic Benefit Credit (a)	$ (37.3)	$ (3.1)	$ (5.3)	$ (4.7)	$ (4.0)	$ (2.1)	$ (2.6)

(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 12 - Voluntary Severance Program for additional information.

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

For the qualified pension plan, discretionary contributions may be made to maintain the funded status of the plan. In the second quarter of 2025, AEP made a discretionary contribution to the qualified pension plan. The following table provides details of the contribution by Registrant:

Company	Qualified Pension Plan
	(in millions)
AEP	$ 94.7
AEP Texas	12.0
APCo	0.4
I&M	2.1
PSO	1.4
SWEPCo	8.8

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 applicable to each public utility subsidiary. 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.

The CODM of AEP is the President and CEO of AEP, who makes operating decisions, allocates resources to and assesses performance based on these reportable segments. The CODM uses earnings (loss) attributable to AEP common shareholders (presented on a GAAP basis) as a measure of segment profit or loss in making these decisions. Earnings (loss) attributable to AEP common shareholders includes intercompany revenues and expenses that are eliminated on the consolidated financial statements.

The tables below represent AEP's reportable segment income statement information for the three and six months ended June 30, 2025 and 2024 and reportable segment balance sheet information as of June 30, 2025 and December 31, 2024. The significant expenses disclosed below align with the segment-level information that is regularly provided to the CODM.

	Three Months Ended June 30, 2025							
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Revenues from:								
External Customers	$ 2,934.5	$ 1,442.6	$ 155.1	$ 551.0	$ 5,083.2	$ 3.7	$ —	$ 5,086.9
Other Operating Segments	80.7	7.6	601.5	15.2	705.0	25.9	(730.9) (b)	—
Total Revenues	3,015.2	1,450.2	756.6	566.2	5,788.2	29.6	(730.9)	5,086.9
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	920.5	203.7	—	493.4	1,617.6	—	(76.2)	1,541.4
Other Operation and Maintenance	981.8	541.1	45.0	(0.3)	1,567.6	20.5	(659.8)	928.3
Depreciation and Amortization	531.3	201.5	121.1	4.3	858.2	(5.0)	(0.1)	853.1
Taxes Other Than Income Taxes	122.9	159.3	77.2	0.3	359.7	0.1	5.2	365.0
Allowance for Equity Funds Used During Construction	16.0	19.6	21.5	—	57.1	—	—	57.1
Interest Expense	201.0	100.0	58.7	2.0	361.7	151.1	(23.3)	489.5
Income Tax Expense (Benefit)	(136.4)	50.9	(139.3)	18.2	(206.6)	(44.3)	—	(250.9)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	0.3	0.1	22.5	—	22.9	(2.3)	—	20.6
Other Segment Items (c)	(22.3)	(10.5)	59.5	(13.8)	12.9	(23.8)	23.3	12.4
Earnings (Loss) Attributable to AEP Common Shareholders	$ 432.7	$ 223.9	$ 578.4	$ 62.1	$ 1,297.1	$ (71.3)	$ —	$ 1,225.8
Gross Property Additions	$ 2,232.6	$ 663.7	$ 383.6	$ 2.8	$ 3,282.7	$ 5.8	$ (9.2)	$ 3,279.3

	Three Months Ended June 30, 2024							
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Revenues from:								
External Customers	$ 2,572.0	$ 1,428.8	$ 108.7	$ 442.5	$ 4,552.0	$ 27.2	$ —	$ 4,579.2
Other Operating Segments	47.0	7.1	381.2	25.0	460.3	30.5	(490.8) (b)	—
Total Revenues	2,619.0	1,435.9	489.9	467.5	5,012.3	57.7	(490.8)	4,579.2
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	870.8	210.5	—	364.8	1,446.1	—	(77.6)	1,368.5
Other Operation and Maintenance	953.2	520.7	45.7	42.4	1,562.0	24.9	(418.1)	1,168.8
Asset Impairments and Other Related Charges	13.4	52.9	—	76.2	142.5	—	—	142.5
Depreciation and Amortization	486.2	226.9	108.9	5.1	827.1	(5.2)	—	821.9
Taxes Other Than Income Taxes	132.9	178.0	77.2	0.5	388.6	0.1	4.9	393.6
Allowance for Equity Funds Used During Construction	12.8	19.8	22.6	—	55.2	—	—	55.2
Interest Expense	190.2	95.8	53.3	4.9	344.2	155.3	(33.9)	465.6
Income Tax Expense (Benefit)	(53.7)	35.4	57.0	(6.3)	32.4	(25.7)	—	6.7
Equity Earnings (Loss) of Unconsolidated Subsidiaries	0.3	(0.7)	26.9	—	26.5	(1.3)	—	25.2
Other Segment Items (c)	(26.6)	(12.0)	(3.4)	(15.3)	(57.3)	(24.9)	33.9	(48.3)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 65.7	$ 146.8	$ 200.7	$ (4.8)	$ 408.4	$ (68.1)	$ —	$ 340.3
Gross Property Additions	$ 679.1	$ 548.8	$ 325.0	$ 10.1	$ 1,563.0	$ 6.4	$ (12.8)	$ 1,556.6

	Six Months Ended June 30, 2025							
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Revenues from:								
External Customers	$ 6,020.0	$ 2,958.1	$ 271.0	$ 1,281.6	$ 10,530.7	$ 19.6	$ —	$ 10,550.3
Other Operating Segments	133.0	18.6	1,027.7	31.5	1,210.8	54.6	(1,265.4) (b)	—
Total Revenues	6,153.0	2,976.7	1,298.7	1,313.1	11,741.5	74.2	(1,265.4)	10,550.3
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,995.9	466.5	—	1,075.9	3,538.3	—	(144.0)	3,394.3
Other Operation and Maintenance	1,865.2	1,118.2	82.4	30.1	3,095.9	36.3	(1,133.0)	1,999.2
Depreciation and Amortization	1,046.5	404.4	237.3	8.4	1,696.6	(10.1)	—	1,686.5
Taxes Other Than Income Taxes	256.5	364.5	152.8	1.0	774.8	0.6	11.6	787.0
Allowance for Equity Funds Used During Construction	32.4	38.1	43.9	—	114.4	—	—	114.4
Interest Expense	401.7	211.6	115.6	3.9	732.8	298.1	(46.5)	984.4
Income Tax Expense (Benefit)	(91.6)	84.7	(72.4)	54.5	(24.8)	(100.6)	—	(125.4)
Equity Earnings of Unconsolidated Subsidiaries	0.6	1.4	45.7	—	47.7	11.1	—	58.8
Other Segment Items (c)	(45.0)	(22.2)	59.6	(25.2)	(32.8)	(42.2)	46.5	(28.5)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 756.8	$ 388.5	$ 813.0	$ 164.5	$ 2,122.8	$ (96.8)	$ —	$ 2,026.0
Gross Property Additions	$ 3,153.2	$ 1,367.7	$ 813.9	$ 6.7	$ 5,341.5	$ 35.8	$ 2.2	$ 5,379.5

	Six Months Ended June 30, 2024							
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Revenues from:								
External Customers	$ 5,473.2	$ 2,912.0	$ 219.2	$ 958.4	$ 9,562.8	$ 42.1	$ —	$ 9,604.9
Other Operating Segments	93.7	14.1	768.0	72.6	948.4	68.4	(1,016.8) (b)	—
Total Revenues	5,566.9	2,926.1	987.2	1,031.0	10,511.2	110.5	(1,016.8)	9,604.9
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,869.9	515.8	—	737.4	3,123.1	—	(178.8)	2,944.3
Other Operation and Maintenance	1,838.5	1,039.9	82.8	73.9	3,035.1	61.0	(847.5)	2,248.6
Asset Impairments and Other Related Charges	13.4	52.9	—	76.2	142.5	—	—	142.5
Depreciation and Amortization	939.8	449.4	217.0	13.3	1,619.5	(10.5)	—	1,609.0
Taxes Other Than Income Taxes	272.6	368.8	152.2	0.7	794.3	0.2	9.5	804.0
Allowance for Equity Funds Used During Construction	24.5	33.9	40.4	—	98.8	—	—	98.8
Interest Expense	347.4	192.0	110.2	10.9	660.5	311.1	(70.4)	901.2
Income Tax Expense (Benefit)	(259.9)	66.9	111.3	18.8	(62.9)	(72.3)	—	(135.2)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	0.7	(0.8)	49.6	0.9	50.4	(0.7)	—	49.7
Other Segment Items (c)	(56.1)	(23.6)	(5.7)	(32.1)	(117.5)	(57.3)	70.4	(104.4)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 626.5	$ 297.1	$ 409.4	$ 132.8	$ 1,465.8	$ (122.4)	$ —	$ 1,343.4
Gross Property Additions	$ 1,480.9	$ 1,121.1	$ 694.6	$ 20.0	$ 3,316.6	$ 9.5	$ (7.8)	$ 3,318.3

	June 30, 2025							
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Total Assets	$57,909.4	$27,526.9	$ 18,705.5	$1,896.9	$ 106,038.7	$ 5,316.2 (d)	$ (3,576.4) (e)	$ 107,778.5
Investments in Equity Method Investees	$ 9.0	$ 3.5	$ 1,036.8	$ —	$ 1,049.3	$ 64.9	$ —	$ 1,114.2

	December 31, 2024							
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Total Assets	$54,996.5	$26,864.3	$ 18,011.9	$1,633.9	$ 101,506.6	$ 5,550.8 (d)	$ (3,979.4) (e)	$ 103,078.0
Investments in Equity Method Investees	$ 9.1	$ 2.0	$ 996.1	$ —	$ 1,007.2	$ 48.7	$ —	$ 1,055.9

(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 intersegment revenues.
(c) Other segment items included in segment earnings (loss) attributable to AEP common shareholders primarily includes Interest and Dividend Income, Non-Service Cost Components of Net Period Benefit Cost and Net Income (Loss) Attributable to Noncontrolling Interests.
(d) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(e) 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. The CODM of each Registrant Subsidiary is the AEP President and CEO, who makes operating decisions, allocates resources to and assesses performance based on these reportable segments. The CODM uses net income (loss) that is reported on the Registrant Subsidiaries' statements of income as a measure of segment profit or loss in making these decisions. Net income (loss) includes intercompany revenues and expenses that are eliminated on the consolidated financial statements. The expenses disclosed on the Registrant Subsidiaries' statements of income align with the segment-level significant expenses that are regularly provided to the CODM. Total Assets is reported on the consolidated financial statements. Gross Property Additions for the Registrant Subsidiaries is represented by the sum of Construction Expenditures and Acquisition of Assets on the consolidated financial statements. See Registrant Subsidiaries statements of income, balance sheets and cash flows for details.

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 ratemaking purposes exclusively by the FERC and earn revenues through tariff rates charged for the use of their electric transmission systems.

The CODM of AEPTCo is the AEP President and CEO, who makes operating decisions, allocates resources to and assesses performance based on these operating segments. The CODM uses earnings (loss) attributable to AEPTCo common shareholders (presented on a GAAP basis) as a measure of segment profit or loss in making these decisions. Earnings (loss) attributable to AEPTCo common shareholders includes intercompany revenues and expenses that are eliminated on the consolidated financial statements. 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 reportable segment. As a result, AEPTCo has one reportable segment. The remainder of AEPTCo's activity is presented in AEPTCo Parent. While not considered a reportable segment, AEPTCo Parent represents the activity of the holding company which primarily relates to debt financing activity and general corporate activities.

The tables below present AEPTCo's reportable segment income statement information for the three and six months ended June 30, 2025 and 2024 and reportable segment balance sheet information as of June 30, 2025 and December 31, 2024. The significant expenses disclosed below align with the segment-level information that is regularly provided to the CODM.

	Three Months Ended June 30, 2025			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 144.6	$ —	$ —	$ 144.6
Sales to AEP Affiliates	597.1	—	—	597.1
Other Revenues	0.1	—	—	0.1
Total Revenues	741.8	—	—	741.8
Other Operation and Maintenance	42.2	—	—	42.2
Depreciation and Amortization	118.9	—	—	118.9
Taxes Other Than Income Taxes	75.8	—	—	75.8
Interest Income	0.9	84.0	(83.5) (a)	1.4
Allowance for Equity Funds Used During Construction	21.5	—	—	21.5
Interest Expense	77.5	62.6	(83.5) (a)	56.6
Income Tax Expense (Benefit)	(156.0)	10.7	—	(145.3)
Other Segment Items (b)	—	60.7	—	60.7
Earnings (Loss) Attributable to AEPTCo Common Shareholders	$ 605.8	$ (50.0) (c)	$ —	$ 555.8
Gross Property Additions	$ 365.1	$ —	$ —	$ 365.1

	Three Months Ended June 30, 2024			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 97.0	$ —	$ —	$ 97.0
Sales to AEP Affiliates	377.8	—	—	377.8
Other Revenues	0.4	—	—	0.4
Total Revenues	475.2	—	—	475.2
Other Operation and Maintenance	44.9	0.1	—	45.0
Depreciation and Amortization	106.7	—	—	106.7
Taxes Other Than Income Taxes	75.5	—	—	75.5
Interest Income	3.5	61.7	(60.9) (a)	4.3
Allowance for Equity Funds Used During Construction	22.5	—	—	22.5
Interest Expense	51.4	60.9	(60.9) (a)	51.4
Income Tax Expense	47.5	0.2	—	47.7
Earnings Attributable to AEPTCo Common Shareholders	$ 175.2	$ 0.5 (c)	$ —	$ 175.7
Gross Property Additions	$ 321.3	$ —	$ —	$ 321.3

	Six Months Ended June 30, 2025						
	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
	(in millions)					
Revenues from:						
External Customers	$ 248.9	$ —		$ —		$ 248.9
Sales to AEP Affiliates	1,019.9	—		—		1,019.9
Other Revenues	0.1	—		—		0.1
Total Revenues	1,268.9	—		—		1,268.9
Other Operation and Maintenance	76.4	0.2		—		76.6
Depreciation and Amortization	233.0	—		—		233.0
Taxes Other Than Income Taxes	149.9	—		—		149.9
Interest Income	1.0	173.3		(172.5)	(a)	1.8
Allowance for Equity Funds Used During Construction	43.9	—		—		43.9
Interest Expense	161.5	122.6		(172.5)	(a)	111.6
Income Tax Expense (Benefit)	(95.2)	10.7		—		(84.5)
Other Segment Items (b)	—	60.7		—		60.7
Earnings (Loss) Attributable to AEPTCo Common Shareholders	$ 788.2	$ (20.9)	(c)	$ —		$ 767.3
Gross Property Additions	$ 786.9	$ —		$ —		$ 786.9

	Six Months Ended June 30, 2024					
	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
	(in millions)					
Revenues from:						
External Customers	$ 194.0	$ —		$ —		$ 194.0
Sales to AEP Affiliates	761.2	—		—		761.2
Other Revenues	2.8	—		—		2.8
Total Revenues	958.0	—		—		958.0
Other Operation and Maintenance	78.6	1.6		—		80.2
Depreciation and Amortization	212.6	—		—		212.6
Taxes Other Than Income Taxes	148.9	—		—		148.9
Interest Income	4.5	118.8		(117.1)	(a)	6.2
Allowance for Equity Funds Used During Construction	40.4	—		—		40.4
Interest Expense	106.1	117.2		(117.1)	(a)	106.2
Income Tax Expense	99.8	—		—		99.8
Earnings Attributable to AEPTCo Common Shareholders	$ 356.9	$ —	(c)	$ —		$ 356.9
Gross Property Additions	$ 657.8	$ —		$ —		$ 657.8

	June 30, 2025					
	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
	(in millions)					
Total Assets	$ 17,080.1	$ 6,241.3	(d)	$ (6,288.6)	(e)	$ 17,032.8

	December 31, 2024					
	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
	(in millions)					
Total Assets	$ 16,887.7	$ 8,670.4	(d)	$ (9,187.8)	(e)	$ 16,370.3

(a) Elimination of intercompany interest income/interest expense on affiliated debt arrangement.
(b) Other segment items included in segment earnings (loss) attributable to AEPTCo common shareholders primarily includes Net Income (Loss) Attributable to Noncontrolling Interests.
(c) Includes elimination of AEPTCo Parent's equity earnings in the State Transcos.
(d) Primarily relates to Notes Receivable from the State Transcos.
(e) Primarily relates to 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 AEP Board.

The following table represents the gross notional volume of the Registrants' outstanding derivative contracts:

Notional Volume of Derivative Instruments

	June 30, 2025							December 31, 2024						
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)	373.7	—	51.9	16.0	1.9	17.8	14.5	282.4	—	23.6	7.7	2.0	5.0	4.6
Natural Gas (MMBtus)	174.3	—	45.3	—	—	54.1	22.3	152.8	—	42.2	—	—	46.2	15.4
Heating Oil and Gasoline (Gallons)	6.6	1.9	0.8	1.2	1.0	0.6	0.8	7.9	2.0	0.9	2.0	1.1	0.7	0.9
Interest Rate (USD)	$ 49.3	$ —	$ —	$ —	$ —	$ —	$ —	$ 59.3	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt (USD)	$ 950.0	$ —	$ —	$ —	$ —	$ —	$ —	$ 950.0	$ —	$ —	$ —	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

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

Cash Flow Hedging Strategies

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third-party contractual agreements and risk profiles. AEP netted cash collateral received from third-parties against short-term and long-term risk management assets in the amounts of $95 million and $87 million as of June 30, 2025 and December 31, 2024, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for the Registrant Subsidiaries as of June 30, 2025 and December 31, 2024. AEP netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $15 million and $3 million as of June 30, 2025 and December 31, 2024, respectively. I&M netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $10 million and $600 thousand as of June 30, 2025 and December 31, 2024, respectively. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was not material for the other Registrant Subsidiaries as of June 30, 2025 and December 31, 2024.

Location and Fair Value of Derivative Assets and Liabilities Recognized on 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.

	June 30, 2025						
	AEP	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
Assets:				(in millions)			
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 748.4	$ —	$ 111.4	$ 29.4	$ —	$ 100.0	$ 71.3
Hedging Contracts - Commodity	67.0	—	—	—	—	—	—
Total Current Risk Management Assets	815.4	—	111.4	29.4	—	100.0	71.3
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	527.6	—	2.1	3.5	—	0.1	0.4
Hedging Contracts - Commodity	79.8	—	—	—	—	—	—
Total Long-term Risk Management Assets	607.4	—	2.1	3.5	—	0.1	0.4
Total Assets	$ 1,422.8	$ —	$ 113.5	$ 32.9	$ —	$ 100.1	$ 71.7
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 390.3	$ 0.2	$ 5.2	$ 27.5	$ 6.0	$ 8.8	$ 4.2
Hedging Contracts - Commodity	20.1	—	—	—	—	—	—
Hedging Contracts - Interest Rate	26.9	—	—	—	—	—	—
Total Current Risk Management Liabilities	437.3	0.2	5.2	27.5	6.0	8.8	4.2
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	443.8	—	1.2	4.1	41.8	2.6	0.9
Hedging Contracts - Commodity	10.8	—	—	—	—	—	—
Hedging Contracts - Interest Rate	21.0	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	475.6	—	1.2	4.1	41.8	2.6	0.9
Total Liabilities	$ 912.9	$ 0.2	$ 6.4	$ 31.6	$ 47.8	$ 11.4	$ 5.1
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 509.9	$ (0.2)	$ 107.1	$ 1.3	$ (47.8)	$ 88.7	$ 66.6

	December 31, 2024						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:	(in millions)						
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 425.0	$ —	$ 40.2	$ 28.5	$ —	$ 22.3	$ 19.1
Hedging Contracts - Commodity	54.1	—	—	—	—	—	—
Total Current Risk Management Assets	479.1	—	40.2	28.5	—	22.3	19.1
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	475.4	—	2.0	1.2	—	1.6	—
Hedging Contracts - Commodity	84.6	—	—	—	—	—	—
Total Long-term Risk Management Assets	560.0	—	2.0	1.2	—	1.6	—
Total Assets	$ 1,039.1	$ —	$ 42.2	$ 29.7	$ —	$ 23.9	$ 19.1
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 304.1	$ 0.3	$ 6.6	$ 10.5	$ 7.5	$ 7.6	$ 3.4
Hedging Contracts - Commodity	11.3	—	—	—	—	—	—
Hedging Contracts - Interest Rate	36.3	—	—	—	—	—	—
Total Current Risk Management Liabilities	351.7	0.3	6.6	10.5	7.5	7.6	3.4
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	390.7	—	0.8	2.1	40.2	0.2	—
Hedging Contracts - Commodity	2.7	—	—	—	—	—	—
Hedging Contracts - Interest Rate	35.3	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	428.7	—	0.8	2.1	40.2	0.2	—
Total Liabilities	$ 780.4	$ 0.3	$ 7.4	$ 12.6	$ 47.7	$ 7.8	$ 3.4
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 258.7	$ (0.3)	$ 34.8	$ 17.1	$ (47.7)	$ 16.1	$ 15.7

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.

	June 30, 2025						
	AEP	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
Assets:				(in millions)			
Current Risk Management Assets							
Gross Amounts Recognized	$ 815.4	$ —	$ 111.4	$ 29.4	$ —	$ 100.0	$ 71.3
Gross Amounts Offset	(346.1)	—	(2.7)	(17.1)	—	(3.1)	(0.9)
Net Amounts Presented	469.3	—	108.7	12.3	—	96.9	70.4
Long-term Risk Management Assets							
Gross Amounts Recognized	607.4	—	2.1	3.5	—	0.1	0.4
Gross Amounts Offset	(348.5)	—	(0.9)	(3.5)	—	(0.1)	(0.4)
Net Amounts Presented	258.9	—	1.2	—	—	—	—
Total Assets	$ 728.2	$ —	$ 109.9	$ 12.3	$ —	$ 96.9	$ 70.4
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 437.3	$ 0.2	$ 5.2	$ 27.5	$ 6.0	$ 8.8	$ 4.2
Gross Amounts Offset	(331.2)	(0.2)	(3.2)	(26.6)	(0.1)	(3.2)	(0.9)
Net Amounts Presented	106.1	—	2.0	0.9	5.9	5.6	3.3
Long-term Risk Management Liabilities							
Gross Amounts Recognized	475.6	—	1.2	4.1	41.8	2.6	0.9
Gross Amounts Offset	(284.0)	—	(0.9)	(3.8)	—	(0.1)	(0.4)
Net Amounts Presented	191.6	—	0.3	0.3	41.8	2.5	0.5
Total Liabilities	$ 297.7	$ —	$ 2.3	$ 1.2	$ 47.7	$ 8.1	$ 3.8
Total MTM Derivative Contract Net Assets (Liabilities)	$ 430.5	$ —	$ 107.6	$ 11.1	$ (47.7)	$ 88.8	$ 66.6

	December 31, 2024						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:	(in millions)						
Current Risk Management Assets							
Gross Amounts Recognized	$ 479.1	$ —	$ 40.2	$ 28.5	$ —	$ 22.3	$ 19.1
Gross Amounts Offset	(268.7)	—	(4.5)	(10.1)	—	(1.7)	(1.0)
Net Amounts Presented	210.4	—	35.7	18.4	—	20.6	18.1
Long-term Risk Management Assets							
Gross Amounts Recognized	560.0	—	2.0	1.2	—	1.6	—
Gross Amounts Offset	(270.9)	—	(0.6)	(1.2)	—	(0.2)	—
Net Amounts Presented	289.1	—	1.4	—	—	1.4	—
Total Assets	$ 499.5	$ —	$ 37.1	$ 18.4	$ —	$ 22.0	$ 18.1
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 351.7	$ 0.3	$ 6.6	$ 10.5	$ 7.5	$ 7.6	$ 3.4
Gross Amounts Offset	(251.7)	(0.3)	(4.6)	(10.2)	(0.2)	(1.8)	(1.1)
Net Amounts Presented	100.0	—	2.0	0.3	7.3	5.8	2.3
Long-term Risk Management Liabilities							
Gross Amounts Recognized	428.7	—	0.8	2.1	40.2	0.2	—
Gross Amounts Offset	(204.3)	—	(0.6)	(1.7)	—	(0.2)	—
Net Amounts Presented	224.4	—	0.2	0.4	40.2	—	—
Total Liabilities	$ 324.4	$ —	$ 2.2	$ 0.7	$ 47.5	$ 5.8	$ 2.3
Total MTM Derivative Contract Net Assets (Liabilities)	$ 175.1	$ —	$ 34.9	$ 17.7	$ (47.5)	$ 16.2	$ 15.8

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 June 30, 2025						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ 12.3	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(13.0)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.2	12.2	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	0.7	—	0.9	(0.1)	—	—	—
Other Operation	(0.1)	(0.1)	—	—	—	—	—
Maintenance	(0.3)	(0.1)	—	—	—	—	(0.1)
Regulatory Assets (a)	(6.1)	0.1	(0.1)	(1.0)	3.4	(5.6)	(3.0)
Regulatory Liabilities (a)	77.2	—	2.5	4.3	2.6	28.4	41.5
Total Gain (Loss) on Risk Management Contracts	$ 70.7	$ (0.1)	$ 3.5	$ 15.4	$ 6.0	$ 22.8	$ 38.4

	Three Months Ended June 30, 2024						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ 4.3	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(53.0)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	—	4.3	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	0.7	—	0.7	0.1	—	—	—
Other Operation	0.3	0.1	—	0.1	—	—	—
Maintenance	0.5	0.1	0.1	0.1	0.1	—	0.1
Regulatory Assets (a)	31.7	0.1	15.2	4.6	(3.1)	8.9	0.2
Regulatory Liabilities (a)	92.5	(0.2)	12.6	7.1	—	33.8	34.6
Total Gain (Loss) on Risk Management Contracts	$ 77.0	$ 0.1	$ 28.6	$ 16.3	$ (3.0)	$ 42.7	$ 34.9

Location of Gain (Loss)	Six Months Ended June 30, 2025						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ (20.2)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	60.2	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.3	(20.5)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	3.8	—	3.8	—	—	—	—
Other Operation	(0.2)	(0.1)	—	—	—	—	—
Maintenance	(0.4)	(0.1)	—	—	—	—	(0.1)
Regulatory Assets (a)	(4.5)	0.2	—	(1.0)	(0.3)	(1.8)	(1.9)
Regulatory Liabilities (a)	230.1	—	59.5	14.8	5.8	67.0	70.7
Total Gain (Loss) on Risk Management Contracts	$ 268.8	$ —	$ 63.6	$ (6.7)	$ 5.5	$ 65.2	$ 68.7

Location of Gain (Loss)	Six Months Ended June 30, 2024						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Vertically Integrated Utilities Revenues	$ (21.4)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(97.7)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.1	(21.5)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1.7	—	1.6	0.1	—	—	—
Other Operation	0.3	0.1	—	0.1	—	—	—
Maintenance	0.6	0.1	0.1	0.1	0.1	—	0.1
Regulatory Assets (a)	45.2	0.3	15.1	3.0	5.5	7.7	5.1
Regulatory Liabilities (a)	145.2	—	25.7	9.3	—	52.1	49.6
Total Gain (Loss) on Risk Management Contracts	$ 73.9	$ 0.5	$ 42.6	$ (8.9)	$ 5.6	$ 59.8	$ 54.8

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

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

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

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

Accounting for Fair Value Hedging Strategies (Applies to AEP)

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

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

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

	Carrying Amount of the Hedged Liabilities		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Liabilities	
	June 30, 2025	December 31, 2024	June 30, 2025	December 31, 2024
	(in millions)			
Long-term Debt (a) (b)	$ (919.1)	$ (898.6)	$ 29.5	$ 49.3

(a) Amounts included within Noncurrent Liabilities line item Long-term Debt and Current Liabilities line item Long-term Debt Due Within One Year on the balance sheet.
(b) Amounts include $(18) million and $(22) million as of June 30, 2025 and December 31, 2024, respectively, for the fair value hedge adjustment of hedged debt obligations for which hedge accounting has been discontinued.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions)			
Gain (Loss) on Interest Rate Contracts:				
Fair Value Hedging Instruments (a)	$ 20.5	$ 18.2	$ 23.6	$ 1.8
Fair Value Portion of Long-term Debt (a)	(20.5)	(18.2)	(23.6)	(1.8)

(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 six months ended June 30, 2025 and 2024, AEP applied cash flow hedging to outstanding power derivatives and the Registrant Subsidiaries did not.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2025, the Registrants did not apply cash flow hedging to outstanding interest rate derivatives. During the three and six months ended June 30, 2024, AEP and AEP Texas 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

	June 30, 2025				December 31, 2024			
	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	$ 91.5	$ 0.2	$ 37.1	$ 0.8	$ 98.5	$ 3.3	$ 33.9	$ 2.8
AEP Texas	—	5.9	—	0.7	—	6.3	—	0.7
APCo	—	4.7	—	0.8	—	5.1	—	0.8
I&M	—	(4.9)	—	(0.4)	—	(5.1)	—	(0.4)
PSO	—	2.4	—	0.2	—	3.6	—	0.2
SWEPCo	—	0.9	—	0.3	—	1.0	—	0.3

As of June 30, 2025, 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 June 30, 2025 and December 31, 2024. The Registrant Subsidiaries had no derivative contracts with collateral triggering events in a net liability position as of June 30, 2025 and December 31, 2024.

Cross-Acceleration Triggers (Applies to AEP)

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 $48 million and $72 million and no cash collateral posted as of June 30, 2025 and December 31, 2024, respectively. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required. The Registrant Subsidiaries had no derivative contracts with cross-acceleration provisions in a net liability position as of June 30, 2025 and December 31, 2024.

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 $153 million and $164 million and no cash collateral posted as of June 30, 2025 and December 31, 2024, respectively, after considering contractual netting arrangements. If a cross-default provision would have been triggered, settlement at fair value would have been required. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $2 million, $8 million and $2 million, respectively, and no cash collateral posted as of June 30, 2025. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $1 million, $4 million and $2 million, respectively, and no cash collateral posted as of December 31, 2024. The other Registrant Subsidiaries had no derivative contracts with cross-default provisions in a net liability position as of June 30, 2025 and December 31, 2024.

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:

	June 30, 2025		December 31, 2024	
Company	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
AEP	$ 44,525.5	$ 41,138.3	$ 42,642.8	$ 38,964.7
AEP Texas	6,832.3	6,303.0	6,441.6	5,831.4
AEPTCo	6,098.5	5,346.8	5,768.1	4,853.1
APCo	5,772.0	5,577.2	5,660.3	5,346.0
I&M	3,510.9	3,250.4	3,494.3	3,153.8
OPCo	3,717.1	3,138.3	3,715.7	3,203.4
PSO	3,524.0	3,310.8	2,855.6	2,562.1
SWEPCo	3,983.0	3,593.4	3,980.8	3,431.5

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

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

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

	June 30, 2025			
Other Temporary Investments and Restricted Cash	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$ 51.3	$ —	$ —	$ 51.3
Other Cash Deposits	16.1	—	—	16.1
Fixed Income Securities – Mutual Funds (b)	159.8	—	(3.0)	156.8
Equity Securities – Mutual Funds	14.0	25.1	—	39.1
Total Other Temporary Investments and Restricted Cash	$ 241.2	$ 25.1	$ (3.0)	$ 263.3

	December 31, 2024			
Other Temporary Investments and Restricted Cash	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(in millions)			
Restricted Cash (a)	$ 43.1	$ —	$ —	$ 43.1
Other Cash Deposits	13.9	—	—	13.9
Fixed Income Securities – Mutual Funds (b)	167.2	—	(5.3)	161.9
Equity Securities – Mutual Funds	12.7	26.9	—	39.6
Total Other Temporary Investments and Restricted Cash	$ 236.9	$ 26.9	$ (5.3)	$ 258.5

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

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

	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
	(in millions)			
Proceeds from Investment Sales	$ 6.6	$ —	$ 16.6	$ 3.0
Purchases of Investments	5.0	1.5	6.5	3.0
Gross Realized Gains on Investment Sales	0.2	—	4.2	0.3
Gross Realized Losses on Investment Sales	0.3	—	0.5	0.2

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

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

	June 30, 2025				December 31, 2024			
	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	$ 28.1	$ —	$ —	$ —	$ 23.3	$ —	$ —	$ —
Fixed Income Securities:								
United States Government	1,298.6	3.3	(9.0)	(16.9)	1,322.8	8.2	(5.3)	(20.2)
Corporate Debt	274.8	20.5	(1.0)	(7.1)	211.3	0.7	(9.8)	(5.8)
State and Local Government	—	—	—	—	—	—	—	—
Subtotal Fixed Income Securities	1,573.4	23.8	(10.0)	(24.0)	1,534.1	8.9	(15.1)	(26.0)
Equity Securities - Domestic	3,008.2	2,444.9	(0.5)	—	2,837.7	2,288.9	(0.4)	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 4,609.7	$ 2,468.7	$ (10.5)	$ (24.0)	$4,395.1	$ 2,297.8	$ (15.5)	$ (26.0)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(in millions)			
Proceeds from Investment Sales	$ 717.9	$ 584.6	$ 1,294.4	$ 1,154.1
Purchases of Investments	728.8	598.6	1,330.0	1,187.1
Gross Realized Gains on Investment Sales	2.4	4.9	4.3	10.3
Gross Realized Losses on Investment Sales	1.8	4.2	2.5	5.4

The base cost of fixed income securities was $1.6 billion and $1.5 billion as of June 30, 2025 and December 31, 2024, respectively. The base cost of equity securities was $564 million and $549 million as of June 30, 2025 and December 31, 2024, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of June 30, 2025 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 350.0
After 1 year through 5 years	635.8
After 5 years through 10 years	231.2
After 10 years	356.4
Total	$ 1,573.4

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.

<u>AEP</u>

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2025

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 48.2	$ —	$ —	$ 3.1	$ 51.3
Other Cash Deposits (a)	—	—	—	16.1	16.1
Fixed Income Securities – Mutual Funds	156.8	—	—	—	156.8
Equity Securities – Mutual Funds (b)	39.1	—	—	—	39.1
Total Other Temporary Investments and Restricted Cash	244.1	—	—	19.2	263.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	2.3	758.9	499.6	(655.5)	605.3
Cash Flow Hedges:					
Commodity Hedges (c)	—	128.0	17.5	(22.6)	122.9
Total Risk Management Assets	2.3	886.9	517.1	(678.1)	728.2
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	15.4	—	—	12.7	28.1
Fixed Income Securities:					
United States Government	—	1,298.6	—	—	1,298.6
Corporate Debt	—	274.8	—	—	274.8
Subtotal Fixed Income Securities	—	1,573.4	—	—	1,573.4
Equity Securities – Domestic (b)	3,008.2	—	—	—	3,008.2
Total Spent Nuclear Fuel and Decommissioning Trusts	3,023.6	1,573.4	—	12.7	4,609.7
Total Assets	$ 3,270.0	$ 2,460.3	$ 517.1	$ (646.2)	$ 5,601.2
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 4.7	$ 682.0	$ 132.1	$ (576.0)	$ 242.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	27.3	2.2	(22.5)	7.0
Fair Value Hedges	—	47.9	—	—	47.9
Total Risk Management Liabilities	$ 4.7	$ 757.2	$ 134.3	$ (598.5)	$ 297.7

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 43.1	$ —	$ —	$ —	$ 43.1
Other Cash Deposits (a)	—	—	—	13.9	13.9
Fixed Income Securities – Mutual Funds	161.9	—	—	—	161.9
Equity Securities – Mutual Funds (b)	39.6	—	—	—	39.6
Total Other Temporary Investments and Restricted Cash	244.6	—	—	13.9	258.5
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	2.9	597.3	291.6	(517.2)	374.6
Cash Flow Hedges:					
Commodity Hedges (c)	—	115.6	21.9	(12.6)	124.9
Total Risk Management Assets	2.9	712.9	313.5	(529.8)	499.5
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	9.6	—	—	13.7	23.3
Fixed Income Securities:					
United States Government	—	1,322.8	—	—	1,322.8
Corporate Debt	—	211.3	—	—	211.3
State and Local Government	—	—	—	—	—
Subtotal Fixed Income Securities	—	1,534.1	—	—	1,534.1
Equity Securities – Domestic (b)	2,837.7	—	—	—	2,837.7
Total Spent Nuclear Fuel and Decommissioning Trusts	2,847.3	1,534.1	—	13.7	4,395.1
Total Assets	$ 3,094.8	$ 2,247.0	$ 313.5	$ (502.2)	$ 5,153.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 4.4	$ 534.1	$ 147.7	$ (433.6)	$ 252.6
Cash Flow Hedges:					
Commodity Hedges (c)	—	12.6	0.2	(12.6)	0.2
Fair Value Hedges	—	71.6	—	—	71.6
Total Risk Management Liabilities	$ 4.4	$ 618.3	$ 147.9	$ (446.2)	$ 324.4

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2025

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 13.3	$ —	$ —	$ —	$ 13.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.2	$ —	$ (0.2)	$ —

December 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 23.5	$ —	$ —	$ —	$ 23.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.3	$ —	$ (0.3)	$ —

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2025

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 18.2	$ —	$ —	$ —	$ 18.2
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	4.8	108.6	(3.5)	109.9
Total Assets	$ 18.2	$ 4.8	$ 108.6	$ (3.5)	$ 128.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 6.0	$ 0.3	$ (4.0)	$ 2.3

December 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 16.2	$ —	$ —	$ —	$ 16.2
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	6.5	35.2	(4.6)	37.1
Total Assets	$ 16.2	$ 6.5	$ 35.2	$ (4.6)	$ 53.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 6.9	$ —	$ (4.7)	$ 2.2

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2025

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 17.1	$ 13.0	$ (17.8)	$ 12.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	15.4	—	—	12.7	28.1
Fixed Income Securities:					
United States Government	—	1,298.6	—	—	1,298.6
Corporate Debt	—	274.8	—	—	274.8
State and Local Government	—	—	—	—	—
Subtotal Fixed Income Securities	—	1,573.4	—	—	1,573.4
Equity Securities - Domestic (b)	3,008.2	—	—	—	3,008.2
Total Spent Nuclear Fuel and Decommissioning Trusts	3,023.6	1,573.4	—	12.7	4,609.7
Total Assets	$ 3,023.6	$ 1,590.5	$ 13.0	$ (5.1)	$ 4,622.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 28.1	$ 0.7	$ (27.6)	$ 1.2

December 31, 2024

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 19.9	$ 6.9	$ (8.4)	$ 18.4
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	9.6	—	—	13.7	23.3
Fixed Income Securities:					
United States Government	—	1,322.8	—	—	1,322.8
Corporate Debt	—	211.3	—	—	211.3
Subtotal Fixed Income Securities	—	1,534.1	—	—	1,534.1
Equity Securities - Domestic (b)	2,837.7	—	—	—	2,837.7
Total Spent Nuclear Fuel and Decommissioning Trusts	2,847.3	1,534.1	—	13.7	4,395.1
Total Assets	$ 2,847.3	$ 1,554.0	$ 6.9	$ 5.3	$ 4,413.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 9.2	$ 0.5	$ (9.0)	$ 0.7

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2025

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 47.7	$ —	$ 47.7

December 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.2	$ 47.5	$ (0.2)	$ 47.5

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2025

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 3.0	$ 97.0	$ (3.1)	$ 96.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 11.2	$ 0.1	$ (3.2)	$ 8.1

December 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 3.1	$ 20.8	$ (1.9)	$ 22.0
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 7.0	$ 0.8	$ (2.0)	$ 5.8

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2025

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Restricted Cash for Securitized Funding	$ 16.7	$ —	$ —	$ —	$ 16.7
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	1.0	70.7	(1.3)	70.4
Total Assets	$ 16.7	$ 1.0	$ 70.7	$ (1.3)	$ 87.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 3.5	$ 1.6	$ (1.3)	$ 3.8

December 31, 2024

Assets:	Level 1	Level 2	Level 3	Other	Total
			(in millions)		
Restricted Cash for Securitized Funding	$ 3.4	$ —	$ —	$ —	$ 3.4
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	1.0	18.1	(1.0)	18.1
Total Assets	$ 3.4	$ 1.0	$ 18.1	$ (1.0)	$ 21.5
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 2.8	$ 0.6	$ (1.1)	$ 2.3

(a) Amounts in "Other'' column primarily represent cash deposits in bank accounts with financial institutions or third-parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) Amounts in "Other'' column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging.''

(d) The June 30, 2025 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 2025 and $(1) million in periods 2026-2028; Level 2 matures $5 million in 2025, $68 million in periods 2026-2028 and $4 million in periods 2029-2030; Level 3 matures $175 million in 2025, $203 million in periods 2026-2028, $12 million in periods 2029-2030 and $(23) million in periods 2031-2034. 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, 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 2025; Level 2 matures $16 million in 2025, $43 million in periods 2026-2028, $4 million in periods 2029-2030; Level 3 matures $106 million in 2025, $45 million in periods 2026-2028, $9 million in periods 2029-2030 and $(16) million in periods 2031-2034. 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 June 30, 2025	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of March 31, 2025	$ 122.8	$ 8.0	$ 3.9	$ (51.2)	$ 15.4	$ 13.1
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	52.7	10.1	2.9	(0.2)	17.6	18.6
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(3.4)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(0.8)	—	—	—	—	—
Settlements	(101.2)	(18.1)	(6.9)	2.1	(32.9)	(31.7)
Transfers into Level 3 (d) (e)	5.4	—	—	—	—	—
Transfers out of Level 3 (e)	(2.2)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	309.5	108.3	12.4	1.6	96.8	69.1
Balance as of June 30, 2025	$ 382.8	$ 108.3	$ 12.3	$ (47.7)	$ 96.9	$ 69.1

Three Months Ended June 30, 2024	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of March 31, 2024	$ 119.1	$ 4.0	$ 1.0	$ (41.0)	$ 7.7	$ 5.3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	42.5	15.7	4.1	—	7.5	8.4
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	4.5	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	0.9	—	—	—	—	—
Settlements	(64.3)	(19.7)	(5.2)	2.3	(15.2)	(13.6)
Transfers into Level 3 (d) (e)	2.5	—	—	—	—	—
Transfers out of Level 3 (e)	(0.2)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	183.2	67.8	14.6	(4.5)	49.4	38.0
Balance as of June 30, 2024	$ 288.2	$ 67.8	$ 14.5	$ (43.2)	$ 49.4	$ 38.1

Six Months Ended June 30, 2025	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2024	$ 165.6	$ 35.2	$ 6.4	$ (47.5)	$ 20.0	$ 17.5
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	154.3	49.4	12.9	—	37.9	42.2
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	16.8	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	5.9	—	—	—	—	—
Settlements	(263.2)	(84.6)	(19.2)	4.3	(57.9)	(59.7)
Transfers into Level 3 (d) (e)	(0.3)	—	—	—	—	—
Transfers out of Level 3 (e)	0.2	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	303.5	108.3	12.2	(4.5)	96.9	69.1
Balance as of June 30, 2025	$ 382.8	$ 108.3	$ 12.3	$ (47.7)	$ 96.9	$ 69.1

Six Months Ended June 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)	90.8	24.1	7.3	(0.8)	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)	13.9	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	1.7	—	—	—	—	—
Settlements	(158.3)	(46.5)	(10.0)	4.9	(44.8)	(36.0)
Transfers into Level 3 (d) (e)	7.1	—	—	—	—	—
Transfers out of Level 3 (e)	1.9	—	—	—	—	0.5
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	191.7	67.8	14.4	3.3	49.4	38.9
Balance as of June 30, 2024	$ 288.2	$ 67.8	$ 14.5	$ (43.2)	$ 49.4	$ 38.1

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Included in cash flow hedges on the statements of comprehensive income.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses or accounts payable.

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

Significant Unobservable Inputs
June 30, 2025

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Input/Range Weighted Average (b)
		(in millions)						
AEP	Energy Contracts	$ 204.2	$ 129.7	Discounted Cash Flow	Forward Market Price	$ 4.80	$ 129.40	$ 47.56
AEP	FTRs	312.9	4.6	Discounted Cash Flow	Forward Market Price	(32.49)	28.81	(0.20)
APCo	FTRs	108.6	0.3	Discounted Cash Flow	Forward Market Price	(1.40)	14.50	2.10
I&M	FTRs	13.0	0.7	Discounted Cash Flow	Forward Market Price	(0.90)	14.50	1.05
OPCo	Energy Contracts	—	47.7	Discounted Cash Flow	Forward Market Price	12.54	75.71	41.08
PSO	FTRs	97.0	0.1	Discounted Cash Flow	Forward Market Price	(32.49)	5.35	(5.18)
SWEPCo	FTRs	70.7	1.6	Discounted Cash Flow	Forward Market Price	(32.49)	5.35	(5.18)

December 31, 2024

Company	Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Input/Range Weighted Average (b)
		(in millions)						
AEP	Energy Contracts	$ 221.2	$ 144.6	Discounted Cash Flow	Forward Market Price	$ 2.75	$ 149.30	$ 49.34
AEP	FTRs	92.3	3.3	Discounted Cash Flow	Forward Market Price	(29.48)	19.70	0.24
APCo	FTRs	35.2	—	Discounted Cash Flow	Forward Market Price	(0.25)	9.32	1.56
I&M	FTRs	6.9	0.5	Discounted Cash Flow	Forward Market Price	(4.07)	9.32	1.34
OPCo	Energy Contracts	—	47.5	Discounted Cash Flow	Forward Market Price	14.53	72.40	42.44
PSO	FTRs	20.8	0.8	Discounted Cash Flow	Forward Market Price	(29.48)	10.54	(3.88)
SWEPCo	FTRs	18.1	0.6	Discounted Cash Flow	Forward Market Price	(29.48)	10.54	(3.88)

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

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs for the Registrants as of June 30, 2025 and December 31, 2024:

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 2025 and 2024, adjusted for tax expense associated with certain discrete items. In the second quarter of 2025, AEPTCo, APCo, I&M, PSO and SWEPCo recorded tax benefits of $256 million, $24 million, $38 million, $14 million and $46 million, respectively, contributing to a total AEP Consolidated benefit of $383 million, related to the remeasurement of Excess ADIT associated with the FERC order related to the treatment of NOLCs in transmission formula rates, driving a reduction to the interim ETR resulting in AEP's tax rate of (24.2)% for three months ended June 30, 2025 and (6.4)% for six months ended June 30, 2025 as shown below.

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

	Three Months Ended June 30, 2025							
	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 %	0.9 %	2.5 %	0.8 %	1.1 %	1.0 %	3.2 %	(2.8)%
Tax Reform Excess ADIT Reversal	(0.4)%	(2.1)%	0.6 %	(2.0)%	2.8 %	(2.7)%	(2.7)%	2.5 %
Remeasurement of Excess ADIT	(37.0)%	— %	(54.3)%	(26.0)%	(40.8)%	— %	(41.4)%	(79.4)%
Production and Investment Tax Credits	(6.7)%	(0.1)%	— %	(0.1)%	(18.7)%	— %	(69.3)%	(40.7)%
Reversal of Origination Flow-Through	— %	0.1 %	0.2 %	(4.1)%	1.8 %	0.6 %	0.3 %	0.9 %
AFUDC Equity	(1.0)%	(1.2)%	(0.8)%	(0.9)%	(0.8)%	(1.5)%	(1.4)%	(1.5)%
Flow-Through of CAMT	(0.3)%	— %	— %	(3.4)%	— %	— %	— %	— %
Other	(0.4)%	0.1 %	— %	— %	— %	(0.1)%	0.2 %	(0.9)%
Effective Income Tax Rate	(24.2)%	18.7 %	(30.8)%	(14.7)%	(33.6)%	18.3 %	(90.1)%	(100.9)%

	Three Months Ended June 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	0.9 %	0.5 %	2.3 %	3.0 %	(3.7)%	(1.2)%	(2.9)%	(0.1)%
Tax Reform Excess ADIT Reversal	(6.0)%	(1.2)%	0.2 %	(2.9)%	(15.2)%	(34.9)%	(3.4)%	2.0 %
Remeasurement of Excess ADIT	(1.7)%	3.9 %	— %	— %	(46.2)%	— %	— %	— %
Production and Investment Tax Credits	(11.0)%	(0.2)%	— %	(0.1)%	1.8 %	— %	(70.6)%	15.9 %
Reversal of Origination Flow-Through	1.1 %	0.1 %	0.3 %	(1.0)%	12.0 %	2.7 %	0.3 %	(0.4)%
Other	(2.4)%	(1.3)%	(2.4)%	(2.1)%	(2.0)%	(4.1)%	(1.5)%	0.5 %
Effective Income Tax Rate	1.9 %	22.8 %	21.4 %	17.9 %	(32.3)%	(16.5)%	(57.1)%	38.9 %

	Six Months Ended June 30, 2025							
	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	0.9 %	0.6 %	2.5 %	1.0 %	2.0 %	1.3 %	3.0 %	(2.2)%
Tax Reform Excess ADIT Reversal	(1.4)%	(2.8)%	0.4 %	(2.4)%	0.2 %	(3.2)%	(3.1)%	0.1 %
Remeasurement of Excess ADIT	(19.5)%	— %	(34.4)%	(8.1)%	(24.1)%	— %	(23.5)%	(45.7)%
Production and Investment Tax Credits	(6.6)%	(0.1)%	— %	(0.1)%	(15.8)%	— %	(51.3)%	(36.6)%
Reversal of Origination Flow-Through	0.2 %	0.1 %	0.2 %	(1.8)%	1.8 %	0.7 %	0.2 %	0.8 %
AFUDC Equity	(1.1)%	(1.1)%	(1.1)%	(0.7)%	(0.7)%	(1.6)%	(1.0)%	(1.4)%
Other	0.1 %	(0.1)%	— %	0.1 %	— %	— %	0.1 %	(0.2)%
Effective Income Tax Rate	(6.4)%	17.6 %	(11.4)%	9.0 %	(15.6)%	18.2 %	(54.6)%	(64.2)%

	Six Months Ended June 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	1.8 %	0.4 %	2.5 %	2.6 %	2.3 %	0.6 %	— %	(2.4)%
Tax Reform Excess ADIT Reversal	(6.0)%	(1.2)%	0.2 %	(10.0)%	(3.4)%	(10.6)%	(2.8)%	(1.5)%
Remeasurement of Excess ADIT	(19.0)%	2.4 %	— %	— %	(55.8)%	— %	(116.8)%	303.0 %
Production and Investment Tax Credits	(7.0)%	(0.2)%	— %	(0.1)%	(0.5)%	— %	(61.3)%	69.3 %
Other	(2.0)%	(1.1)%	(1.8)%	(1.4)%	(0.7)%	(0.4)%	(0.4)%	(1.2)%
Effective Income Tax Rate	(11.2)%	21.3 %	21.9 %	12.1 %	(37.1)%	10.6 %	(160.3)%	388.2 %

Federal and State Income Tax Audit Status

AEP is not currently under IRS audit and the statute of limitations (SOL) for the IRS to examine AEP and subsidiaries originally filed federal return has expired for tax years prior to 2021. In July 2025, AEP received notification that its 2023 federal income tax return was selected for IRS examination.

AEP and subsidiaries file income tax returns in various state and local jurisdictions. AEP and subsidiaries are not currently under any state and local income tax examinations. Generally, the SOL have expired for tax years prior to 2021. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Federal Legislation

On July 4, 2025, President Trump signed H.R. 1 into law, commonly known as the One Big Beautiful Bill Act (OBBBA). Most notably for AEP, this budget reconciliation legislation modifies and accelerates the phase out of wind and solar PTCs and ITCs, adds new restrictions to guard against certain foreign ownership or influence with respect to otherwise credit-eligible projects and makes 100% bonus depreciation permanent for our non-regulated entities. With the exception of bonus depreciation, this legislation is prospective and has no material impact on the current period financial statements. Following enactment of the legislation, on July 7, 2025, the President issued an Executive Order directing the Department of Treasury to issue new and revised wind and solar tax credit guidance within 45 days, which could impose further practical limits on the development of wind and solar projects. In addition to this potential near term guidance, additional significant guidance from the Department of Treasury and the IRS is expected on the tax provisions included in the OBBBA. AEP will continue to monitor any issued guidance and evaluate the impact on future net income, cash flows and financial condition.

12. 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

These expenses were primarily included in Other Operation and Maintenance on the statements of income and Other Current Liabilities on the balance sheets. Settlement accounting was triggered for the qualified pension plan in November 2024 under the accounting guidance for "Compensation - Retirement Benefits" and a settlement charge of $90 million was recorded. As of June 30, 2025, all incurred expenses have been settled. AEP will seek recovery for the portion of the expense related to regulated operations. See Note 7 - Benefit Plans for additional information associated with the plan.

13. 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 2024, approximately $0.4 billion of common stock was offered and sold under the ATM program. There were no issuances under the ATM program for the six months ended June 30, 2025. Approximately $1.3 billion of equity is available for issuance under the ATM program upon the filing of a prospectus supplement.

Forward Sale of Equity

In March 2025, AEP entered into separate forward sale agreements with nonaffiliated forward purchasers relating to 22,549,020 shares of AEP's common stock at an initial price of $102.00 per share, exclusive of an underwriting discount equal to $2.244 per share. Except in certain specified circumstances that would require physical share settlement, AEP may elect to settle the forward sale transaction by means of physical, cash or net share settlement. The timing of the settlement of the forward sale agreements is also at AEP's discretion and management currently expects settlement to occur on or prior to December 31, 2026. To the extent the forward sale agreements are physically settled, AEP will issue common stock to the forward purchasers and receive cash proceeds based on the applicable forward sale price on the settlement date as defined in the forward sale agreements. As of June 30, 2025, AEP expects approximately $2.25 billion of net cash proceeds from the full physical settlement of the forward sale agreements and management anticipates using any future proceeds for general corporate purposes, which may include capital contributions to utility subsidiaries, acquisitions or repayment of debt. The forward sale transactions will be classified as equity transactions because they are indexed to AEP's common stock and physical settlement is within AEP's control.

Long-term Debt Outstanding (Applies to AEP)

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

Type of Debt	June 30, 2025	December 31, 2024
	(in millions)	
Senior Unsecured Notes	$ 37,019.1	$ 36,410.9
Pollution Control Bonds	1,730.3	1,771.3
Notes Payable	644.5	609.9
Securitization Bonds	1,021.0	578.0
Spent Nuclear Fuel Obligation (a)	323.2	316.3
Junior Subordinated Notes	2,581.2	2,579.1
Other Long-term Debt	1,206.2	377.3
Total Long-term Debt Outstanding	44,525.5	42,642.8
Long-term Debt Due Within One Year	3,212.4	3,335.0
Long-term Debt	$ 41,313.1	$ 39,307.8

(a) Pursuant to the Nuclear Waste Policy Act of 1982, I&M, a nuclear licensee, has an obligation to the United States Department of Energy for SNF disposal. The obligation includes a one-time fee for nuclear fuel consumed prior to April 7, 1983. Trust fund assets related to this obligation were $375 million and $367 million as of June 30, 2025 and December 31, 2024, 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 six months of 2025 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)	Interest Rate	Due Date
Issuances:		**(in millions)**	**(%)**	
AEP Texas	Other Long-term Debt	$ 400.0	Variable	2026
AEPTCo	Senior Unsecured Notes	425.0	5.38	2035
APCo	Other Long-term Debt	425.0	Variable	2026
APCo	Pollution Control Bonds	104.4	3.70	2028
I&M	Notes Payable	100.0	4.89	2029
I&M	Pollution Control Bonds	150.0	3.70	2029
PSO	Senior Unsecured Notes	800.0	5.45	2036
Non-Registrant:				
KPCo	Other Long-term Debt	150.0	Variable	2026
KPCo	Securitization Bonds	477.7	5.30	2045
Transource Energy	Other Long-term Debt	29.5	Variable	2025
WPCo	Other Long-term Debt	125.0	Variable	2026
Total Issuances		$ 3,186.6		

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

Company	Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements and Principal Payments:		**(in millions)**	**(%)**	
AEP Texas	Securitization Bonds	$ 10.3	2.06	2025
AEP Texas	Securitization Bonds	1.9	2.29	2029
AEPTCo	Senior Unsecured Notes	50.0	3.66	2025
AEPTCo	Senior Unsecured Notes	40.0	3.76	2025
APCo	Other Long-term Debt	0.1	13.72	2026
APCo	Pollution Control Bonds	104.4	3.75	2025
APCo	Securitization Bonds	13.9	3.77	2028
APCo	Senior Unsecured Notes	300.0	3.40	2025
I&M	Notes Payable	1.1	Variable	2025
I&M	Notes Payable	2.6	0.93	2025
I&M	Notes Payable	7.5	3.44	2026
I&M	Notes Payable	8.7	5.93	2027
I&M	Notes Payable	10.1	6.01	2028
I&M	Notes Payable	16.3	6.41	2028
I&M	Notes Payable	3.5	4.89	2029
I&M	Other Long-term Debt	0.2	6.00	2025
I&M	Pollution Control Bonds	40.0	0.75	2025
I&M	Pollution Control Bonds	50.0	2.75	2025
I&M	Pollution Control Bonds	100.0	3.05	2025
PSO	Other Long-term Debt	0.3	3.00	2027
PSO	Senior Unsecured Notes	125.0	3.17	2025
Non-Registrant:				
KPCo	Other Long-term Debt	150.0	Variable	2025
KPCo	Other Long-term Debt	150.0	Variable	2026
Transource Energy	Senior Unsecured Notes	1.2	2.75	2050
WPCo	Senior Unsecured Notes	122.0	3.70	2025
WPCo	Notes Payable	15.0	6.89	2034
Total Retirements and Principal Payments		$ 1,324.1		

Financing Activities Subsequent Events

In July 2025, AEGCo retired $45 million of Pollution Control Bonds.

In July 2025, I&M retired $10 million of Notes Payable related to DCC Fuel.

In July 2025, Transource Energy issued $4 million of variable rate Other Long-term Debt due in 2028.

In July 2025, AEP made a capital contribution of $200 million to AEP Texas.

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 June 30, 2025. 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 AEP Board 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 June 30, 2025 and December 31, 2024 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 six months ended June 30, 2025 are described in the following table:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of June 30, 2025	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 468.4	$ 112.8	$ 182.7	$ 62.5	$ (109.5)	$ 600.0	
AEPTCo	403.6	312.2	192.0	39.8	32.7	820.0	(a)
APCo	263.5	242.1	141.3	30.0	(154.8)	750.0	
I&M	145.2	19.3	77.2	6.1	(25.7)	500.0	
OPCo	270.9	165.9	71.6	81.7	(203.0)	600.0	
PSO	505.1	391.5	204.1	167.0	(319.7)	750.0	
SWEPCo	471.9	76.3	285.9	10.2	76.3	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 June 30, 2025 and December 31, 2024 are included in Advances to Affiliates on the subsidiaries' balance sheets. The Nonutility Money Pool participants' activity for the six months ended June 30, 2025 is described in the following table:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of June 30, 2025
		(in millions)	
AEP Texas	$ 7.2	$ 7.1	$ 7.1
SWEPCo	2.4	2.3	2.4

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of borrowings from AEP as of June 30, 2025 and December 31, 2024 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 six months ended June 30, 2025 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 June 30, 2025	Loans to AEP as of June 30, 2025	Authorized Short-term Borrowing Limit (a)
				(in millions)			
AEPTCo Parent	$ 106.6	$ 132.6	$ 13.6	$ 38.2	$ 10.5	$ —	$ —
SWTCo	2.0	—	1.9	—	2.0	—	50.0
Midwest Transmission Holdings	—	32.6	—	11.0	—	—	—

(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:

	Six Months Ended June 30, 2025	2024
Maximum Interest Rate	4.83 %	5.79 %
Minimum Interest Rate	4.14 %	5.14 %

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 Six Months Ended June 30, 2025	2024	Average Interest Rate for Funds Loaned to the Utility Money Pool for Six Months Ended June 30, 2025	2024
AEP Texas	4.69 %	5.70 %	4.72 %	5.49 %
AEPTCo	4.68 %	5.71 %	4.62 %	5.62 %
APCo	4.69 %	5.73 %	4.58 %	5.64 %
I&M	4.69 %	5.67 %	4.64 %	5.68 %
OPCo	4.65 %	5.70 %	4.70 %	5.52 %
PSO	4.67 %	5.64 %	4.68 %	— %
SWEPCo	4.69 %	5.64 %	4.65 %	— %

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

	Six Months Ended June 30, 2025			Six Months Ended June 30, 2024		
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	4.76 %	4.64 %	4.70 %	5.79 %	5.56 %	5.69 %
SWEPCo	4.76 %	4.64 %	4.70 %	5.79 %	5.56 %	5.68 %

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

Six Months Ended June 30,	**Maximum Interest Rate for Funds Borrowed from AEP**	**Minimum Interest Rate for Funds Borrowed from AEP**	**Maximum Interest Rate for Funds Loaned to AEP**	**Minimum Interest Rate for Funds Loaned to AEP**	**Average Interest Rate for Funds Borrowed from AEP**	**Average Interest Rate for Funds Loaned to AEP**
2025	4.76 %	4.63 %	4.76 %	4.63 %	4.69 %	4.69 %
2024	5.79 %	5.55 %	5.79 %	5.55 %	5.68 %	5.68 %

Short-term Debt (Applies to AEP and SWEPCo)

Outstanding short-term debt was as follows:

		June 30, 2025		December 31, 2024	
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	4.57 %	$ 900.0	4.73 %
AEP	Commercial Paper	600.0	4.62 %	1,618.3	4.70 %
SWEPCo	Notes Payable	1.6	6.68 %	5.5	6.69 %
	Total Short-term Debt	$ 1,501.6		$ 2,523.8	

(a) Weighted-average rate as of June 30, 2025 and December 31, 2024, 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 June 30, 2025, the affiliated utility subsidiaries were in compliance with all requirements under the agreement.

Accounts receivable information for AEP Credit was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2025	2024	2025	2024
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	4.53 %	5.51 %	4.57 %	5.56 %
Net Uncollectible Accounts Receivable Written-Off	$ 6.1	$ 5.8	$ 13.9	$ 13.9

	June 30, 2025	December 31, 2024
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,233.9	$ 1,117.0
Short-term – Securitized Debt of Receivables	900.0	900.0
Delinquent Securitized Accounts Receivable	58.5	56.2
Bad Debt Reserves Related to Securitization	45.1	44.5
Unbilled Receivables Related to Securitization	390.6	335.5

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	June 30, 2025	December 31, 2024
	(in millions)	
APCo	$ 197.4	$ 192.7
I&M	182.9	160.5
OPCo	477.4	470.7
PSO	158.1	111.4
SWEPCo	189.7	153.5

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

Company	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
	(in millions)			
APCo	$ 3.3	$ 3.9	$ 7.2	$ 8.1
I&M	3.5	3.8	7.0	7.9
OPCo	7.5	7.4	14.9	14.8
PSO	2.8	3.4	5.7	6.8
SWEPCo	3.7	4.3	7.8	9.1

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

Company	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
	(in millions)			
APCo	$ 429.8	$ 447.3	$ 1,034.6	$ 983.3
I&M	545.4	502.1	1,130.2	1,031.8
OPCo	735.2	771.5	1,595.5	1,617.2
PSO	431.9	425.0	806.7	786.6
SWEPCo	456.0	471.9	884.1	897.3

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. AEP’s interests in non-consolidated VIEs are accounted for under the equity method of accounting.

Consolidated Variable Interest Entities

Cost Recovery Funding (Applies to AEP)

In June 2025, Cost Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to plant retirement costs, deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, deferred purchased power expenses, under-recovered purchased power rider costs and issuance-related expenses, including KPSC advisor expenses. Management concluded that KPCo is the primary beneficiary of Cost Recovery Funding because KPCo has the power to direct the most significant activities of the VIE and KPCo’s equity interest could potentially be significant. Therefore, KPCo is required to consolidate Cost Recovery Funding. As of June 30, 2025, $9 million of the securitized bonds was included in Long-term Debt Due Within One Year and $459 million was included in Long-term Debt on the balance sheet. Cost Recovery Funding’s securitized assets were $468 million as of June 30, 2025, which was presented separately on the face of the balance sheet.

The securitized assets represent the right to impose and collect KPCo recovery charges from KPCo’s customers. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to KPCo or any other AEP entity. KPCo acts as the servicer for Cost Recovery Funding’s securitized assets and remits all related amounts collected from customers to Cost Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Cost Recovery Funding’s assets and liabilities on the balance sheet.

The 2024 Annual Report includes a detailed discussion of other Registrants’ consolidated VIEs.

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

June 30, 2025

	Consolidated VIEs											
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Restoration Funding**		**APCo Appalachian Consumer Rate Relief Funding**		**SWEPCo Storm Recovery Funding**	**KPCo Cost Recovery Funding**		**AEP Credit**	**Protected Cell of EIS**	**Transource Energy**
	(in millions)											
ASSETS												
Current Assets	$ 3.1	$ 95.0	$ 18.6		$ 16.0		$ 18.1	$ 3.1		$1,235.0	$ 209.9	$ 58.6
Net Property, Plant and Equipment	—	181.1	—		—		—	—		—	—	621.8
Other Noncurrent Assets	97.1	98.1	110.6	(a)	93.7	(b)	324.7	469.4	(c)	10.7	—	7.9
Total Assets	$ 100.2	$374.2	$ 129.2		$ 109.7		$ 342.8	$ 472.5		$1,245.7	$ 209.9	$ 688.3
LIABILITIES AND EQUITY												
Current Liabilities	$ 16.6	$ 94.8	$ 30.7		$ 30.8		$ 28.5	$ 10.7		$1,179.5	$ 46.6	$ 30.1
Noncurrent Liabilities	83.4	279.4	97.2		77.0		312.6	459.4		1.0	105.6	333.1
Equity	0.2	—	1.3		1.9		1.7	2.4		65.2	57.7	325.1
Total Liabilities and Equity	$ 100.2	$374.2	$ 129.2		$ 109.7		$ 342.8	$ 472.5		$1,245.7	$ 209.9	$ 688.3

(a) Includes an intercompany item eliminated in consolidation of $5 million.
(b) Includes an intercompany item eliminated in consolidation of $1 million.
(c) Includes an intercompany item eliminated in consolidation of $16 million.

December 31, 2024

	Consolidated VIEs									
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Restoration Funding**		**APCo Appalachian Consumer Rate Relief Funding**		**SWEPCo Storm Recovery Funding**	**AEP Credit**	**Protected Cell of EIS**	**Transource Energy**
	(in millions)									
ASSETS										
Current Assets	$ 6.0	$ 79.3	$ 21.3		$ 14.2		$ 3.4	$ 1,118.3	$ 218.5	$ 40.2
Net Property, Plant and Equipment	—	132.3	—		—		—	—	—	598.3
Other Noncurrent Assets	110.8	63.6	121.9	(a)	109.6	(b)	331.4	10.5	—	3.5
Total Assets	$ 116.8	$ 275.2	$ 143.2		$ 123.8		$ 334.8	$ 1,128.8	$ 218.5	$ 642.0
LIABILITIES AND EQUITY										
Current Liabilities	$ 20.1	$ 79.2	$ 30.7		$ 30.5		$ 24.4	$ 1,068.8	$ 54.7	$ 57.2
Noncurrent Liabilities	96.3	196.0	111.2		91.4		308.7	1.0	96.0	274.3
Equity	0.4	—	1.3		1.9		1.7	59.0	67.8	310.5
Total Liabilities and Equity	$ 116.8	$ 275.2	$ 143.2		$ 123.8		$ 334.8	$ 1,128.8	$ 218.5	$ 642.0

(a) Includes an intercompany item eliminated in consolidation of $5 million.
(b) Includes an intercompany item eliminated in consolidation of $1 million.

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

The 2024 Annual Report 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 AEP, PSO and SWEPCo.

Asset Retirement Obligations

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms, solar farms and certain coal mining facilities. AEP records ARO for the decommissioning of the Cook Plant. The table below summarizes significant changes to the Registrants ARO recorded in 2025 and should be read in conjunction with the Property, Plant and Equipment note within the 2024 Annual Report.

The following is a reconciliation of the aggregate carrying amounts of ARO for AEP, PSO and SWEPCo:

Company	ARO as of December 31, 2024	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of June 30, 2025
			(in millions)			
AEP (b)(c)(d)(e)(f)(g)	$ 3,611.7	$ 84.6	$ 17.4	$ (42.4)	$ 34.8	$ 3,706.1
PSO (b)(e)(f)(g)	121.8	3.6	15.5	(1.3)	(2.8)	136.8
SWEPCo (b)(d)(e)(f)	278.7	8.7	—	(27.5)	31.6	291.5

(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.
(d) Includes ARO related to Sabine and DHLC.
(e) Includes ARO related to asbestos removal.
(f) Includes ARO related to renewables.
(g) Includes ARO related to incurred ARO liabilities due to the acquisitions of Pixley Solar Energy Facility and Flat Ridge IV Wind Energy Facility. See the "Acquisitions" section of Note 6 for additional information.

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 June 30, 2025						
	VIU	T&D	AEPTHCo	G&M	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,029.7	$ 611.8	$ —	$ —	$ —	$ —	$ 1,641.5
Commercial Revenues	749.5	420.6	—	—	—	—	1,170.1
Industrial Revenues (a)	704.6	145.1	—	—	—	(0.3)	849.4
Other Retail Revenues	60.5	14.1	—	—	—	—	74.6
Total Retail Revenues	2,544.3	1,191.6	—	—	—	(0.3)	3,735.6
Wholesale and Competitive Retail Revenues:							
Generation Revenues	237.3	—	—	38.3	—	—	275.6
Transmission Revenues (b)	157.2	197.4	698.3	—	—	(622.1)	430.8
Retail, Trading and Marketing Revenues (c)	—	—	—	538.6	—	(15.3)	523.3
Total Wholesale and Competitive Retail Revenues	394.5	197.4	698.3	576.9	—	(637.4)	1,229.7
Other Revenues from Contracts with Customers (d)	49.4	46.2	8.9	2.4	27.4	(44.2)	90.1
Total Revenues from Contracts with Customers	2,988.2	1,435.2	707.2	579.3	27.4	(681.9)	5,055.4
Other Revenues:							
Alternative Revenue Programs (a) (e)	14.5	12.4	49.5	—	—	(47.0)	29.4
Other Revenues (a) (f)	12.5	2.6	(0.1)	(13.1)	2.2	(2.0)	2.1
Total Other Revenues	27.0	15.0	49.4	(13.1)	2.2	(49.0)	31.5
Total Revenues	$ 3,015.2	$ 1,450.2	$ 756.6	$ 566.2	$ 29.6	$ (730.9)	$ 5,086.9

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEP Transmission Holdco were $558 million. The affiliated revenues for Vertically Integrated Utilities were $65 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Generation & Marketing were $16 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Corporate and Other were $26 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 June 30, 2024						
	VIU	T&D	AEPTHCo	G&M	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 949.0	$ 650.2	$ —	$ —	$ —	$ —	$ 1,599.2
Commercial Revenues	649.8	391.1	—	—	—	—	1,040.9
Industrial Revenues (a)	652.8	123.0	—	—	—	(0.1)	775.7
Other Retail Revenues	55.8	13.7	—	—	—	—	69.5
Total Retail Revenues	2,307.4	1,178.0	—	—	—	(0.1)	3,485.3
Wholesale and Competitive Retail Revenues:							
Generation Revenues	149.0	—	—	23.7	—	(0.1)	172.6
Transmission Revenues (b)	123.0	208.3	496.6	—	—	(397.0)	430.9
Renewable Generation Revenues (a)	—	—	—	8.2	—	(1.4)	6.8
Retail, Trading and Marketing Revenues (c)	—	—	—	485.5	0.3	(23.7)	462.1
Total Wholesale and Competitive Retail Revenues	272.0	208.3	496.6	517.4	0.3	(422.2)	1,072.4
Other Revenues from Contracts with Customers (d)	47.4	38.9	6.2	1.0	55.2	(48.8)	99.9
Total Revenues from Contracts with Customers	2,626.8	1,425.2	502.8	518.4	55.5	(471.1)	4,657.6
Other Revenues:							
Alternative Revenue Programs (a) (e)	(12.1)	6.7	(12.9)	—	—	(17.3)	(35.6)
Other Revenues (a) (f)	4.3	4.0	—	(50.9)	2.2	(2.4)	(42.8)
Total Other Revenues	(7.8)	10.7	(12.9)	(50.9)	2.2	(19.7)	(78.4)
Total Revenues	$ 2,619.0	$ 1,435.9	$ 489.9	$ 467.5	$ 57.7	$ (490.8)	$ 4,579.2

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEP Transmission Holdco were $393 million. The affiliated revenues for Vertically Integrated Utilities were $41 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Generation & Marketing were $24 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Corporate and Other were $30 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 June 30, 2025						
	AEP Texas	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 180.2	$ —	$ 365.2	$ 190.1	$ 431.5	$ 190.4	$ 191.3
Commercial Revenues	114.6	—	194.0	192.2	306.2	135.2	155.4
Industrial Revenues (a)	41.7	—	210.5	156.7	103.5	91.3	103.2
Other Retail Revenues	10.1	—	28.2	1.3	4.1	26.4	2.7
Total Retail Revenues	346.6	—	797.9	540.3	845.3	443.3	452.6
Wholesale Revenues:							
Generation Revenues (b)	—	—	77.9	138.2	—	1.5	48.6
Transmission Revenues (c)	175.4	682.3	45.9	18.6	22.0	16.0	55.4
Total Wholesale Revenues	175.4	682.3	123.8	156.8	22.0	17.5	104.0
Other Revenues from Contracts with Customers (d)	9.1	8.9	18.5	26.9	37.3	6.8	5.7
Total Revenues from Contracts with Customers	531.1	691.2	940.2	724.0	904.6	467.6	562.3
Other Revenues:							
Alternative Revenue Programs (a) (e)	0.4	50.5	7.2	1.2	12.1	1.8	8.0
Other Revenues (a)	(0.3)	0.1	0.2	12.0	2.3	0.1	0.1
Total Other Revenues	0.1	50.6	7.4	13.2	14.4	1.9	8.1
Total Revenues	$ 531.2	$ 741.8	$ 947.6	$ 737.2	$ 919.0	$ 469.5	$ 570.4

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for APCo were $36 million primarily related to the PPA with KGPCo.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEPTCo, APCo and SWEPCo were $555 million, $22 million and $21 million, respectively. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for I&M were $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 June 30, 2024						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 184.9	$ —	$ 364.8	$ 190.5	$ 465.3	$ 187.8	$ 120.7
Commercial Revenues	115.0	—	187.1	150.8	276.1	130.1	100.7
Industrial Revenues (a)	34.0	—	205.9	153.1	89.0	91.1	72.3
Other Retail Revenues	9.3	—	28.1	1.3	4.5	25.9	1.7
Total Retail Revenues	343.2	—	785.9	495.7	834.9	434.9	295.4
Wholesale Revenues:							
Generation Revenues (b)	—	—	72.1	54.8	—	2.7	50.1
Transmission Revenues (c)	184.8	483.2	45.6	10.0	23.6	10.2	46.7
Total Wholesale Revenues	184.8	483.2	117.7	64.8	23.6	12.9	96.8
Other Revenues from Contracts with Customers (d)	10.4	6.2	13.1	29.4	28.5	12.4	7.6
Total Revenues from Contracts with Customers	538.4	489.4	916.7	589.9	887.0	460.2	399.8
Other Revenues:							
Alternative Revenue Programs (a) (e)	1.2	(14.2)	(6.5)	—	5.3	(1.4)	(4.0)
Other Revenues (a)	—	—	—	4.4	4.0	—	—
Total Other Revenues	1.2	(14.2)	(6.5)	4.4	9.3	(1.4)	(4.0)
Total Revenues	$ 539.6	$ 475.2	$ 910.2	$ 594.3	$ 896.3	$ 458.8	$ 395.8

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for APCo were $36 million primarily related to the PPA with KGPCo.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEPTCo, APCo and SWEPCo were $389 million, $22 million and $15 million, respectively. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for I&M were $23 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.

	Six Months Ended June 30, 2025						
	VIU	T&D	AEPTHCo	G&M	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 2,382.0	$ 1,350.8	$ —	$ —	$ —	$ —	$ 3,732.8
Commercial Revenues	1,414.7	802.3	—	—	—	—	2,217.0
Industrial Revenues (a)	1,322.4	268.2	—	—	—	(0.5)	1,590.1
Other Retail Revenues	114.9	29.5	—	—	—	—	144.4
Total Retail Revenues	5,234.0	2,450.8	—	—	—	(0.5)	7,684.3
Wholesale and Competitive Retail Revenues:							
Generation Revenues	542.3	—	—	89.3	—	—	631.6
Transmission Revenues (b)	278.1	394.4	1,219.7	—	—	(1,072.3)	819.9
Retail, Trading and Marketing Revenues (c)	—	—	—	1,160.2	(0.2)	(31.5)	1,128.5
Total Wholesale and Competitive Retail Revenues	820.4	394.4	1,219.7	1,249.5	(0.2)	(1,103.8)	2,580.0
Other Revenues from Contracts with Customers (d)	101.0	108.1	17.7	3.4	70.6	(94.6)	206.2
Total Revenues from Contracts with Customers	6,155.4	2,953.3	1,237.4	1,252.9	70.4	(1,198.9)	10,470.5
Other Revenues:							
Alternative Revenue Programs (a) (e)	17.8	15.9	61.3	—	—	(62.3)	32.7
Other Revenues (a) (f)	(20.2)	7.5	—	60.2	3.8	(4.2)	47.1
Total Other Revenues	(2.4)	23.4	61.3	60.2	3.8	(66.5)	79.8
Total Revenues	$ 6,153.0	$ 2,976.7	$ 1,298.7	$ 1,313.1	$ 74.2	$ (1,265.4)	$ 10,550.3

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEP Transmission Holdco were $969 million. The affiliated revenues for Vertically Integrated Utilities were $104 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Generation & Marketing were $32 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Corporate and Other were $55 million. The remaining affiliated amounts were immaterial.

(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

(f) Generation & Marketing includes economic hedge activity.

	Six Months Ended June 30, 2024						
	VIU	T&D	AEPTHCo	G&M	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 2,161.3	$ 1,354.0	$ —	$ —	$ —	$ —	$ 3,515.3
Commercial Revenues	1,294.9	788.1	—	—	—	—	2,083.0
Industrial Revenues (a)	1,299.9	259.1	—	—	—	(0.3)	1,558.7
Other Retail Revenues	111.1	27.6	—	—	—	—	138.7
Total Retail Revenues	4,867.2	2,428.8	—	—	—	(0.3)	7,295.7
Wholesale and Competitive Retail Revenues:							
Generation Revenues	384.9	—	—	51.1	—	—	436.0
Transmission Revenues (b)	241.9	388.1	985.3	—	—	(815.6)	799.7
Renewable Generation Revenues (a)	—	—	—	14.5	—	(2.8)	11.7
Retail, Trading and Marketing Revenues (c)	—	—	—	1,056.9	0.8	(69.9)	987.8
Total Wholesale and Competitive Retail Revenues	626.8	388.1	985.3	1,122.5	0.8	(888.3)	2,235.2
Other Revenues from Contracts with Customers (d)	107.1	89.9	14.3	2.3	115.6	(117.5)	211.7
Total Revenues from Contracts with Customers	5,601.1	2,906.8	999.6	1,124.8	116.4	(1,006.1)	9,742.6
Other Revenues:							
Alternative Revenue Programs (a) (e)	(12.8)	7.4	(12.4)	—	—	(16.3)	(34.1)
Other Revenues (a) (f)	(21.4)	11.9	—	(93.8)	(5.9)	5.6	(103.6)
Total Other Revenues	(34.2)	19.3	(12.4)	(93.8)	(5.9)	(10.7)	(137.7)
Total Revenues	$ 5,566.9	$ 2,926.1	$ 987.2	$ 1,031.0	$ 110.5	$ (1,016.8)	$ 9,604.9

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEP Transmission Holdco were $780 million. The affiliated revenues for Vertically Integrated Utilities were $83 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Generation & Marketing were $70 million. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Corporate and Other were $79 million. The remaining affiliated amounts were immaterial.

(e) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

(f) Generation & Marketing includes economic hedge activity.

	Six Months Ended June 30, 2025						
	AEP Texas	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 352.1	$ —	$ 971.6	$ 422.2	$ 998.7	$ 365.7	$ 383.9
Commercial Revenues	233.9	—	388.5	344.7	568.5	237.1	296.1
Industrial Revenues (a)	81.2	—	401.9	290.4	187.0	161.7	192.9
Other Retail Revenues	21.0	—	56.4	2.5	8.6	46.6	5.4
Total Retail Revenues	688.2	—	1,818.4	1,059.8	1,762.8	811.1	878.3
Wholesale Revenues:							
Generation Revenues (b)	—	—	167.5	333.3	—	5.6	104.3
Transmission Revenues (c)	348.7	1,188.2	87.7	29.0	45.7	29.8	94.3
Total Wholesale Revenues	348.7	1,188.2	255.2	362.3	45.7	35.4	198.6
Other Revenues from Contracts with Customers (d)	18.6	17.8	32.9	56.9	89.6	15.1	15.8
Total Revenues from Contracts with Customers	1,055.5	1,206.0	2,106.5	1,479.0	1,898.1	861.6	1,092.7
Other Revenues:							
Alternative Revenue Program (a) (e)	(1.1)	62.9	13.7	1.0	17.1	1.9	8.8
Other Revenues (a)	(0.2)	—	0.3	(20.6)	7.3	—	—
Total Other Revenues	(1.3)	62.9	14.0	(19.6)	24.4	1.9	8.8
Total Revenues	$ 1,054.2	$ 1,268.9	$ 2,120.5	$ 1,459.4	$ 1,922.5	$ 863.5	$ 1,101.5

(a) Amounts include affiliated and nonaffiliated revenues.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for APCo were $81 million primarily related to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEPTCo, APCo and SWEPCo were $962 million, $41 million and $31 million, respectively. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for I&M were $36 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.

	Six Months Ended June 30, 2024						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 332.2	$ —	$ 891.1	$ 415.3	$ 1,021.8	$ 346.0	$ 303.1
Commercial Revenues	225.9	—	375.4	295.6	562.2	233.1	240.7
Industrial Revenues (a)	69.6	—	402.3	301.0	189.5	171.4	167.3
Other Retail Revenues	19.0	—	56.2	2.6	8.7	47.4	4.3
Total Retail Revenues	646.7	—	1,725.0	1,014.5	1,782.2	797.9	715.4
Wholesale Revenues:							
Generation Revenues (b)	—	—	157.2	192.1	—	4.9	97.2
Transmission Revenues (c)	340.7	958.6	92.7	20.1	47.4	21.0	86.3
Total Wholesale Revenues	340.7	958.6	249.9	212.2	47.4	25.9	183.5
Other Revenues from Contracts with Customers (d)	19.2	14.3	34.8	57.0	70.7	24.4	17.2
Total Revenues from Contracts with Customers	1,006.6	972.9	2,009.7	1,283.7	1,900.3	848.2	916.1
Other Revenues:							
Alternative Revenue Programs (a) (e)	(0.6)	(14.9)	(6.6)	(0.5)	7.9	(1.6)	(4.1)
Other Revenues (a)	—	—	0.1	(21.5)	11.9	—	—
Total Other Revenues	(0.6)	(14.9)	(6.5)	(22.0)	19.8	(1.6)	(4.1)
Total Revenues	$ 1,006.0	$ 958.0	$ 2,003.2	$ 1,261.7	$ 1,920.1	$ 846.6	$ 912.0

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for APCo were $77 million primarily related to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEPTCo, APCo and SWEPCo were $773 million, $43 million and $28 million, respectively. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for I&M were $41 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 June 30, 2025. 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	2025	2026-2027	2028-2029	After 2029	Total
			(in millions)		
AEP	$ 43.7	$ 143.6	$ 48.6	$ 16.1	$ 252.0
APCo	8.0	31.9	25.2	11.4	76.5
I&M	2.2	8.8	6.8	2.4	20.2

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 June 30, 2025 and December 31, 2024.

When the Registrants receive consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have material contract liabilities as of June 30, 2025 and December 31, 2024.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrant Subsidiaries' balance sheets within the Accounts Receivable - Customers line item. The Registrant Subsidiaries' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of June 30, 2025 and December 31, 2024. See "Securitized Accounts Receivable - AEP Credit" section of Note 13 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)			
June 30, 2025	$ 1.4	$ 165.0	$ 80.9	$ 58.1	$ 61.7	$ 16.8	$ 25.8
December 31, 2024	—	131.6	83.7	55.0	63.6	13.0	21.4

CONTROLS AND PROCEDURES

During the second quarter of 2025, management, including the principal executive officer and principal financial officer of each of the Registrants, evaluated the Registrants' disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to the Registrants' management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As of June 30, 2025, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives.

There was no change in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of 2025 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 2024 Annual Report includes a detailed discussion of risk factors. As of June 30, 2025, the risk factors appearing in the 2024 Annual Report are supplemental and updated as follows:

Changes in U.S. or foreign trade policies, including the imposition of tariffs and other protectionist trade measures, and other factors beyond our control may adversely impact our future net income and cash flows and financial condition.

The U.S. administration has taken executive action and proposed additional measures intended to alter the U.S. approach to international trade policy, the terms of certain existing bilateral or multi-lateral trade agreements and trading arrangements with foreign countries. Such changes to U.S. international trade policy, and any retaliatory trade measures that foreign governments may take in response, including the imposition of tariffs, sanctions, export or import controls, or other measures that restrict international trade, or the threat of such actions, could result in additional increases in the cost of certain goods, services and cost of capital and further extend lead times. In addition, related geopolitical and domestic political developments, such as existing and potential trade wars, uncertainty regarding changes in trade policy, and other events beyond our control, have increased and may continue to increase levels of political and economic unpredictability globally and the volatility of global financial markets. As a result, prevailing economic conditions may reduce future net income and cash flows and negatively impact financial condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

On May 15, 2025, Benjamin G. S. Fowke, III, a director of the Company, entered into a Rule 10b5-1 trading agreement ("Rule 10b5-1 Trading Plan") intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) of the Securities Exchange Act of 1934. Mr. Fowke's Rule 10b5-1 Trading Plan provides for an aggregate sale of up to 25,000 shares of common stock through December 12, 2025.

On May 15, 2025, Kelly J. Ferneau, the Executive Vice President and Chief Nuclear Officer of the Company, entered into a Rule 10b5-1 Trading Plan intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) of the Securities Exchange Act of 1934. Ms. Ferneau's Rule 10b5-1 Trading Plan provides for an aggregate sale of up to 10,218 shares of common stock through February 23, 2026.

During the three months ended June 30, 2025, none of the Company's directors or other officers (as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934) adopted, terminated or modified a Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement (as such terms are defined in Item 408 of Regulation S-K of the Securities Act of 1933).

Item 6. Exhibits

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

Exhibit	Description	Previously Filed as Exhibit to:
AEPTCo‡ File No. 3-217143		
*4(a)	Company Order and Officers' Certificate between AEPTCo and The Bank of New York Mellon Trust Company, N.A., as Trustee, dated May 14, 2025, establishing terms of the Notes.	Form 8-K dated May 12, 2025, Exhibit 4(a)
PSO‡ File No. 0-343		
*4(a)	Thirteenth Supplemental Indenture, dated June 1, 2025, between PSO and The Bank of New York Mellon Trust Company, N.A., as Trustee, establishing terms of the Notes.	Form 8-K dated June 23, 2025 Exhibit 4(a)

The exhibits designated with an (X) in the table below are being filed on behalf of the Registrants.

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
10(a)	Amended and Restated Limited Liability Company Agreement, dated June 5, 2025, among AEP Transmission Company, LLC, Midwest Transmission Holdings, LLC and Olympus BidCo L.P.			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
Senior Vice President, 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: July 30, 2025