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, 2026**
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, 2026
American Electric Power Company, Inc.	544,397,352
	($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, 2026

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. (the Company), 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 former 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 Funds Used During Construction.
AGR	AEP Generation Resources, Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
AI	Artificial Intelligence.
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.
Appalachian Recovery Funding	Appalachian Recovery Funding, LLC, a wholly-owned subsidiary of APCo and a consolidated VIE formed for the purpose of issuing and servicing securitization bonds related to certain Virginia jurisdictional Amos and Mountaineer Property, Plant and Equipment balances and deferred storm costs.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
ATM	At-the-Market.
BESS	Battery Energy Storage System.
CAA	Clean Air Act.
CAMT	Corporate Alternative Minimum Tax.
CCN	Certificate of Convenience and Necessity.

Term	Meaning
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.
CPA	Capacity Purchase Agreement.
CPCN	Certificate of Public Convenience and Necessity.
CSAPR	Cross-State Air Pollution Rule.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel XVII, DCC Fuel XVIII, DCC Fuel XIX, DCC Fuel XX, DCC Fuel XXI and DCC Fuel XXII consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
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.
ERCOT Batch Zero Process	A one-time transitional interconnection process established by ERCOT and approved by the PUCT in 2026 that evaluates qualifying large load interconnection requests on a system-wide basis, allocates available transmission capacity, identifies necessary transmission upgrades and requires financial commitments from participating customers. The process applies primarily to large electric loads of 75 MW or greater and serves as the precursor to ERCOT's future recurring batch interconnection framework.
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.
Gigawatt AI	Gigawatt AI Inc., an equity interest joint venture formed to build the AI-centric operating system for utilities.
G&M	Generation & Marketing.
Grid Growth Ventures	Grid Growth Ventures, LLC, a holding company formed by Transource Energy and First Energy Transmission, LLC, in 2025, which is 43.25% owned by AEP.

Term	Meaning
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., a wholly-owned transmission subsidiary of Midwest Transmission Holdings.
IRP	Integrated Resource Plan.
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary. 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.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.
MATS	Mercury and Air Toxic Standards.
Midcontinent Grid Solutions	Midcontinent Grid Solutions, LLC, a holding company formed by Transource Energy and an affiliate of Berkshire Hathaway Energy in 2025, which is 43.25% owned by AEP.
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.
MRBC	Modified Rate Base Cost.
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.
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., a wholly-owned transmission subsidiary of Midwest Transmission Holdings.
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.

Term	Meaning
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PBA	Performance Based Accreditation.
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.
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 five wholly-owned and two majority-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.

Term	Meaning
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.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
UTM	Unified Tracker Mechanism.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
VIU	Vertically Integrated Utilities.
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's service territory.
- 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 or regulations adopted in the states in which we operate or federal legislation or regulations adopted that alters the regulatory framework or that prevents the timely recovery of costs and investments.
- Volatility and instability in financial markets precipitated by disruptive events, including fiscal and monetary policy or uncertainty 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 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.
- 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, hurricanes, 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 plan for, develop, construct, acquire, or integrate a broad range of generation and energy storage resources, as well as related transmission and distribution infrastructure, including obtaining necessary regulatory approvals, permits, and incentives for which the timing is dependent upon the priorities, requirements, processes and determinations of the local policy and regulatory authorities; complying with cost caps and other regulatory or contractual requirements; and recovering associated costs and earning an appropriate return while meeting reliability, affordability, environmental, and customer-service obligations.
- 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 natural disasters or other events.
- Construction and development risks associated with the completion of the 2026-2030 capital investment plan, including shortages or delays in labor, materials, equipment or parts.
- The impact of prolonged or recurring U.S. federal government shutdowns on AEP's operations, regulatory approvals and financial performance, including potential volatility in the capital markets which may interrupt our access to capital.
- New legislation, litigation or government regulation, including changes to tax laws and regulations, oversight of nuclear generation, evolving environmental standards, 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 in wholesale markets.
- Changes in technology, including new, developing, alternative or distributed sources of generation and energy storage.
- 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 AI by us, our customers and our third party vendors and evolving expectations related to sustainability.
- Customer affordability considerations may impact regulatory recovery outcomes and future rate design.
- Changes in utility regulation, policies, methodologies for evaluating and approving load interconnection, and the allocation of costs within RTOs including ERCOT, PJM and SPP and the impacts of potential market changes or our participation within those RTOs.
- Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in ratings impacting the cost of debt.
- The impact of geopolitical developments on global energy markets, including volatility in fuel supply and pricing, power generation economics and customer demand patterns.
- 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.
- The ability to successfully defend against cybersecurity threats.
- Other risks and unforeseen events, including wars and military conflicts, the effects of terrorism (including increased security costs), embargoes, 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, including senior management.
- Projected increases in demand from data centers are subject to uncertainty and may not materialize as expected, or may occur at a different pace or scale than anticipated, which could impact our load forecasts, capital investment plans, cost recovery expectations and financial results.

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, 2025 (the “2025 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 2026 Compared to Second Quarter of 2025

Earnings Attributable to AEP Common Shareholders decreased from $1.2 billion in 2025 to $713 million in 2026 primarily due to:

- The favorable $480 million impact from the receipt of the June 2025 FERC NOLC order related to the treatment of NOLCs in transmission formula rates.
- A decrease in sales volumes in the residential class driven by favorable weather in 2025.

These decreases were partially offset by:

- Investment in transmission assets, which resulted in higher revenues and income.
- An increase due to rate proceedings in AEP's various jurisdictions.
- Favorable mark-to-market economic hedging activity.
- An increase in sales volume driven primarily by new data processing load added in the commercial and industrial customer classes.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

Earnings Attributable to AEP Common Shareholders decreased from $2 billion in 2025 to $1.6 billion in 2026 primarily due to:

- The favorable $480 million impact from the receipt of the June 2025 FERC NOLC order related to the treatment of NOLCs in transmission formula rates.
- Unfavorable mark-to-market economic hedging activity.
- A decrease in sales volumes in the residential class driven by favorable weather in 2025.
- A decrease due to a probable, partial disallowance of the Pirkey Plant net book value in the SWEPCo 2025 Texas Base Rate Case.

These decreases were partially offset by:

- Investment in transmission assets, which resulted in higher revenues and income.
- An increase due to rate proceedings in AEP's various jurisdictions.
- An increase in sales volume driven primarily by new data processing load added in the commercial and industrial customer classes.
- A gain from the sale of a non-utility investment in land at APCo.

See Results of Operations section for additional information by segment.

Non-GAAP Financial Measures

AEP reports its financial results in accordance with GAAP. AEP supplements its reporting of financial information with certain non-GAAP financial measures, such as operating earnings. The most comparable GAAP measure to operating earnings is GAAP earnings. Operating earnings, which could differ from earnings reported in accordance with GAAP, 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, that management believes 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. These non-GAAP measures should not be deemed more useful than, a substitute for, or an alternative to the most comparable GAAP measures.

Reconciliation of 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, 2026							
	AEP	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
	(in millions)							
GAAP Earnings (a)	$ 713	$ 113	$ 192	$ 50	$ 97	$ 109	$ 54	$ 86
Adjustments to GAAP Earnings:								
Mark-to-Market Impact of Commodity Hedging Activities (b)	(8)	—	—	—	—	—	—	—
UTM Partial Disallowance (c)	22	22	—	—	—	—	—	—
Wholesale Customer Contract Agreements (d)	23	—	—	—	—	—	—	23
Income Tax Effect of Specified Items (e)	(8)	(5)	—	—	—	—	—	(5)
Total Specified Items	29	17	—	—	—	—	—	18
Operating Earnings (Non-GAAP)	$ 742	$ 130	$ 192	$ 50	$ 97	$ 109	$ 54	$ 104

(a) Represents the earnings (loss) attributable to common shareholders or AEP member, or net income (loss) for registrants with no noncontrolling interest.
(b) Represents the mark-to-market impact of economic hedging activities which are excluded to align with the recognition of the underlying hedged exposures.
(c) Represents the estimated impact of the probable, partial disallowance of costs included in AEP Texas' UTM filing.
(d) Represents probable liability related to SWEPCo's agreements with certain existing wholesale customers and current discussions with one remaining existing wholesale customer under generation supply contracts, which is expected to result in credits to these wholesale customers.
(e) Tax effect is calculated using the statutory tax rate unless otherwise noted.

	Three Months Ended June 30, 2025							
	AEP	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
	(in millions)							
GAAP Earnings (a)	$ 1,226	$ 121	$ 556	$ 107	$ 124	$ 103	$ 63	$ 116
Adjustments to GAAP Earnings (b):								
Mark-to-Market Impact of Commodity Hedging Activities (c)	20	—	—	—	(10)	—	—	—
FERC NOLC Order (d)	(480)	—	(354)	(29)	(36)	—	(4)	(54)
Total Specified Items	(460)	—	(354)	(29)	(46)	—	(4)	(54)
Operating Earnings (Non-GAAP)	$ 766	$ 121	$ 202	$ 78	$ 78	$ 103	$ 59	$ 62

(a) Represents the earnings (loss) attributable to common shareholders or AEP member, or net income (loss) for registrants with no noncontrolling interest.
(b) Excluding tax related adjustments, all items presented in the table are tax adjusted at the statutory rate unless otherwise noted.
(c) Represents the mark-to-market impact of economic hedging activities which are excluded to align with the recognition of the underlying hedged exposures.
(d) Represents the impact of the FERC NOLC Order for years 2021-2024.

	Six Months Ended June 30, 2026							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
GAAP Earnings (a)	$ 1,587	$ 233	$ 375	$ 245	$ 245	$ 226	$ 69	$ 142
Adjustments to GAAP Earnings:								
Mark-to-Market Impact of Commodity Hedging Activities (b)	18	—	—	—	7	—	—	—
Impact of WVPSC Order (c)	(35)	—	—	(29)	—	—	—	—
Pirkey Plant Partial Disallowance (d)	31	—	—	—	—	—	—	31
UTM Partial Disallowance (e)	22	22	—	—	—	—	—	—
Wholesale Customer Contract Agreements (f)	23	—	—	—	—	—	—	23
Income Tax Effect of Specified Items (g)	(13)	(5)	—	6	(2)	—	—	(11)
Total Specified Items	46	17	—	(23)	5	—	—	43
Operating Earnings (Non-GAAP)	$ 1,633	$ 250	$ 375	$ 222	$ 250	$ 226	$ 69	$ 185

(a) Represents the earnings (loss) attributable to common shareholders or AEP member, or net income (loss) for registrants with no noncontrolling interest.
(b) Represents the mark-to-market impact of economic hedging activities which are excluded to align with the recognition of the underlying hedged exposures.
(c) Represents the impact of the WVPSC order related to the 2024 Modified Rate Base Cost surcharge update filing.
(d) Represents the estimated impact of the probable, partial disallowance of the Pirkey Plant net book value in the 2025 Texas Base Rate Case.
(e) Represents the estimated impact of the probable, partial disallowance of costs included in AEP Texas' UTM filing.
(f) Represents probable liability related to SWEPCo's agreements with certain existing wholesale customers and current discussions with one remaining existing wholesale customer under generation supply contracts, which is expected to result in credits to these wholesale customers.
(g) Tax effect is calculated using the statutory tax rate unless otherwise noted.

	Six Months Ended June 30, 2025							
	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
GAAP Earnings (a)	$ 2,026	$ 223	$ 767	$ 272	$ 182	$ 166	$ 91	$ 164
Adjustments to GAAP Earnings (b):								
Mark-to-Market Impact of Commodity Hedging Activities (c)	6	—	—	—	16	—	—	—
Sale of AEP OnSite Partners (d)	10	—	—	—	—	—	—	—
Impact of Ohio Legislation (e)	27	—	—	—	—	27	—	—
FERC NOLC Order (f)	(480)	—	(354)	(29)	(36)	—	(4)	(54)
Total Specified Items	(437)	—	(354)	(29)	(20)	27	(4)	(54)
Operating Earnings (Non-GAAP)	$ 1,589	$ 223	$ 413	$ 243	$ 162	$ 193	$ 87	$ 110

(a) Represents the earnings (loss) attributable to common shareholders or AEP member, or net income (loss) for registrants with no noncontrolling interest.
(b) Excluding tax related adjustments, all items presented in the table are tax adjusted at the statutory rate unless otherwise noted.
(c) Represents the mark-to-market impact of economic hedging activities which are excluded to align with the recognition of the underlying hedged exposures.
(d) Represents an adjustment to the estimated loss on the sale of AEP OnSite Partners as a result of the contractual working capital true-up.
(e) Represents the reduction in regulatory assets for OVEC-related purchased power costs as a result of approved legislation in Ohio.
(f) Represents the impact of the FERC NOLC Order for years 2021-2024.

ELECTRIC INDUSTRY TRANSFORMATION

The electric utility industry is undergoing a historic transformation, fueled by rapid and projected load growth, especially from data processing and other energy-intensive operations, as well as shifting regulator and customer expectations, evolving public policies, rising stakeholder demands, demographic changes, new competitive pressures, emerging technologies, necessary reliability investments and volatile commodity markets. AEP projects growth in system peak demand across its diversified service territory, with especially strong projected growth in Indiana, Ohio, Oklahoma and Texas. To meet this accelerating demand, AEP outlined a $78 billion, five-year capital plan focused on strengthening transmission infrastructure, adding new generation resources to serve both existing customers and forecasted large load additions and continuing to enhance distribution system reliability. Throughout this investment cycle, AEP remains committed to focusing on customer affordability. AEP expects to utilize various levers to address affordability including incremental load growth, rate design, continued operation and maintenance expense efficiency and financing mechanisms, such as securitizations.

AEP has advanced large load tariff proposals and tariff modifications aimed at enabling the rapid interconnection of committed large load customers while protecting existing customers from increased costs. The new tariffs are designed to protect existing customers by strengthening and lengthening contract terms with large customers. These new protections include contract lengths of up to 20 years and take-or-pay contractual minimums which can require a customer to pay for as much as 80-90% of their contracted demand. In practice, these provisions reduce risks around the buildout of large load infrastructure on existing customers, with a goal of promoting stability and affordability. As of March 31, 2026, these tariff proposals were filed in eight of AEP's jurisdictions, with four receiving approval from state commissions. During the second quarter of 2026, the Virginia State Commission approved APCo's large load tariff proposal, which applies to new large load additions greater than or equal to 150 MW on an aggregated basis or 100 MW on an individual basis. As of June 30, 2026, there were three pending proposals in Michigan, Oklahoma and SWEPCo-Texas. AEP is actively engaging with regulators, policymakers, RTOs, customers and suppliers to connect large load customers to the grid while also advancing system reliability, resiliency and affordability across its service territory.

AEP continues to secure resources to support forecasted load requirements in its regulated jurisdictions including:

- The addition of 1,013 MWs of owned generating capacity in 2026.
- Signing agreements in 2026 to acquire 1,838 MWs in additional generation facilities.
- Requests for proposals seeking approximately 12,100 MWs of generating capacity.
- Capacity purchase agreements to satisfy capacity reserve margins to serve customers.
- Long-term transmission construction partnership with a major U.S.-based infrastructure services company.

PJM Proposed Reforms

In July 2026, the PJM Board approved near-term resource adequacy reforms intended to address projected reliability concerns associated with significant forecasted load growth and capacity shortages. The package directs PJM to seek FERC approval of a Reliability Backstop Procurement mechanism and an Interim Resource Adequacy Service for new large load customers that do not provide sufficient capacity resources to meet their resource adequacy needs. The reforms also include the creation of a Large Load Registry and new requirements for electric distribution utilities to provide information regarding certain large load interconnection requests. PJM expects to conduct a centralized procurement process beginning in September 2026.

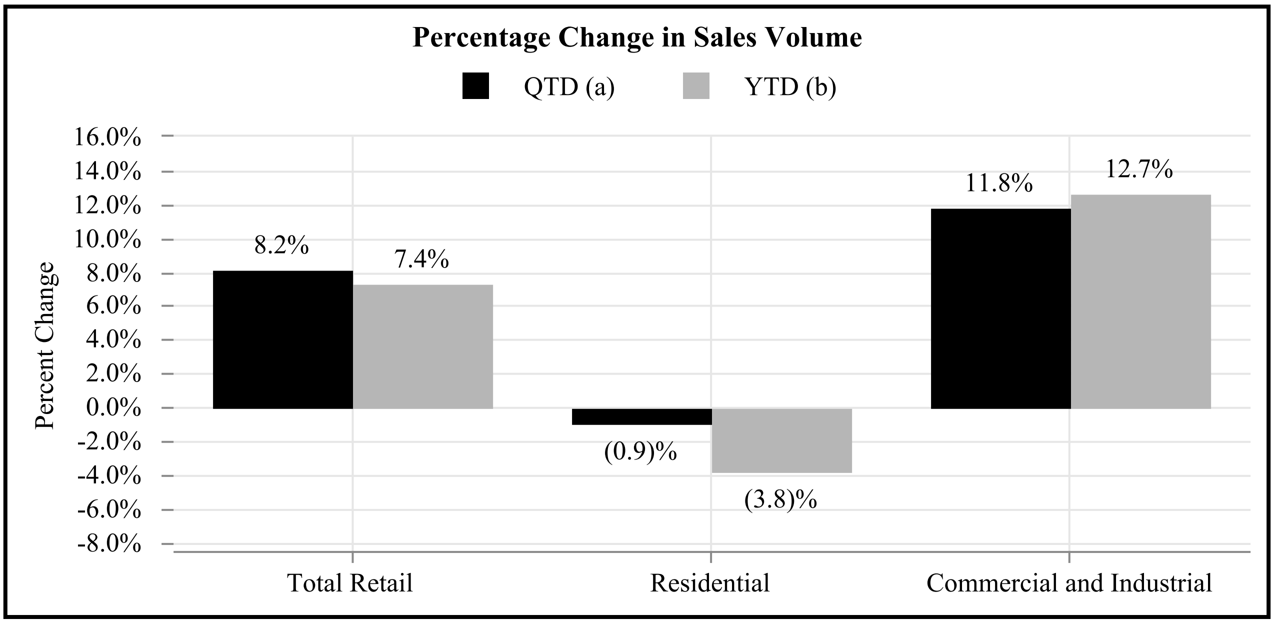
Fixed Resource Requirement entities are excluded from the Reliability Backstop Procurement targets and associated cost allocation. AEP's Fixed Resource Requirement operating companies within PJM also may be affected in their role as electric distribution utilities. Under the proposed framework, beginning June 1, 2027, electric distribution utilities would be required to administer an Interim Resource Adequacy Service for certain new large load customers that do not provide sufficient capacity resources to meet applicable reliability requirements. The proposal also requires electric distribution utilities to administer a FERC-approved compensation mechanism for qualifying large load customers that are directed to reduce their electricity consumption.

The PJM proposal also includes provisions intended to mitigate impacts associated with a transmission owner's withdrawal from PJM. Under the proposal, a withdrawing transmission owner that participates in the Reliability Backstop Procurement program could be required to satisfy certain future obligations associated with resources procured through that program or charges allocated to load on an accelerated basis prior to withdrawal, or otherwise provide for continued payment of such obligations through the applicable commitment term. These provisions are intended to prevent costs associated with committed reliability resources from being shifted to remaining PJM participants.

PJM has not yet filed the proposal with the FERC, and the ultimate form of any approved tariff revisions, implementation requirements, cost recovery mechanisms and operational impacts remains uncertain. At this time, AEP cannot predict the outcome of the FERC proceeding or estimate the potential impact, if any, that any final approved provisions may have on its financial condition, results of operations or cash flows. AEP will continue to monitor the proceeding.

Customer Demand

AEP uses sales volumes by customer class as a way to measure drivers of customer demand. Through the first half of 2026, AEP experienced higher customer demand, driven primarily by new data processing load added in the commercial and industrial customer classes. This growth was partially offset by weather-related impacts in the residential class, including favorable weather in the first and second quarters of 2025 and normal weather through the first half of 2026. The table below shows the percentage change in sales volume by customer class.



(a) Percentage change for the three months ended June 30, 2026 as compared to the three months ended June 30, 2025. Load figures are billed and accrued retail sales excluding firm wholesale load.

(b) Percentage change for the six months ended June 30, 2026 as compared to the six months ended June 30, 2025. Load figures are billed and accrued retail sales excluding firm wholesale load.

New Generation Resources

The growth of AEP's regulated generation portfolio reflects the Company's focus on meeting increasing customer demand for power while balancing cost and reliability.

Acquired Generation Facilities

In March 2026, I&M acquired the Oregon Clean Energy Center (Oregon Plant). In May 2026, APCo acquired the Grover Hill Wind Project (Grover Hill Wind). These transactions reflect the Companies' focus on securing necessary generation to meet future customer demand. See the "Acquisitions" section of Note 6 for additional information. The table below summarizes these acquisitions:

Company	Plant Name	Fuel Type	Location	Acquisition Date	Net Maximum Capacity
					(in MWs)
I&M	Oregon Plant	Natural Gas	Oregon, OH	March 2026	870
APCo	Grover Hill Wind	Wind	Paulding County, OH	May 2026	143
Total Acquired Generation Facilities					1,013

Pending Natural Gas Generation

In December 2024, SWEPCo filed an application for a CCN with the APSC, LPSC and PUCT for 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 Plant. In February 2026, the APSC approved both projects and regulatory proceedings in Louisiana and Texas are still underway. In July 2026, SWEPCo, PUCT staff and certain intervenors filed an unopposed stipulation and settlement agreement with the PUCT agreeing the application for a CCN should be approved. Additionally, in July 2026, SWEPCo and the LPSC staff filed a joint stipulation and term sheet with the LPSC agreeing the application for a CCN should be approved. SWEPCo estimates the combined capital cost of these projects to be approximately $723 million and the projects would be placed in service between December 2027 and May 2028.

In September 2025, PSO filed an application with the OCC seeking regulatory approval of a new 450 MW combustion turbine configuration at its existing Northeastern facility in Oklahoma as part of a project portfolio, which was approved in May 2026. The combustion turbines are projected to be online by the end of 2028.

In February 2026, I&M entered into a PSA to acquire the Big Sandy Peaker Plant, a six-unit, 318 MW combustion turbine plant located in Kenova, West Virginia. In April 2026, I&M filed an application with the IURC seeking approval of the purchase under its EGR plan. The acquisition is expected to close in the second half of 2026.

In April 2026, I&M entered into a PSA to acquire the Sycamore Riverside Energy Center (Sycamore Plant), a 918 MW natural gas and ultra-low sulfur distillate (dual-fuel)-fired generation facility located in Sullivan County, Indiana. I&M filed an application with the IURC in late April seeking a CPCN for the approval of the estimated project costs and associated ratemaking and accounting treatment. A final order from the IURC is expected in December 2026.

In July 2026, I&M filed an application for a CPCN with the IURC for the engineering, procurement, and construction of the Rockport Energy Center, a 1,520 MW combined-cycle natural gas facility located in Spencer County, Indiana. In the application, I&M also seeks approval of the estimated project costs, authority to recover costs associated with the project's development, and approval of specific ratemaking and accounting treatment. A final order from the IURC is expected in the first quarter of 2027.

Significant Approved Renewable Generation and Storage Filings

AEP received approval from various state regulatory commissions to acquire approximately 884 MWs of owned renewable generation and storage facilities, totaling approximately $2.3 billion. The Financial Condition section below includes the estimated cost of these facilities in the Budgeted Capital Expenditures. In addition, AEP received approval from various state regulatory commissions for 924 MWs of renewable PPAs. The following table summarizes regulatory approvals received for active renewable projects that are not yet in service as of June 30, 2026:

Company	Generation Type	Expected Commercial Operation	Owned/PPA	Generating Capacity
				(in MWs)
APCo	Solar	2026-2028	PPA	343
I&M	Wind	2026-2030	PPA	401
I&M	Solar	2027	PPA	180
I&M	Solar	2029	Owned	245
PSO (a)	Wind	2026	Owned	265
PSO (a)	Solar	2027	Owned	150
PSO	BESS	2027-2028	Owned	224
Total Approved Renewable Projects				1,808

(a) PSO has one wind project and one solar project under construction.

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	Resource Type	Projected In-Service Dates	Generating Capacity
				(in MWs)
APCo	May 2026	Owned wind and solar	2029	800
APCo	May 2026	Purchased power from solar, wind and hydroelectric resources	2029/2030	300
I&M (a)	September 2024	Wind, solar, dispatchable resources, BESS and emerging technology resources	2029	4,000
PSO	January 2026	All-source	2029	4,000
SWEPCo	May 2026	All-source	2031	3,000
Total Significant RFPs				12,100

(a) Five wind resources totaling 574 MWs from the 2024 RFP were contracted and approved by the IURC. The 918 MW Sycamore Plant was also selected through the 2024 RFP and was filed with the IURC for approval in April 2026. I&M expects to file several additional projects selected through the 2024 RFP in the second half of 2026.

Capacity Purchase Agreements

In addition to the generation projects discussed above, AEP enters into CPAs to satisfy operating companies' capacity reserve margins to serve customers. The following table includes CPA amounts under contract as of June 30, 2026, by year, for the five-year period 2026-2030:

	APCo	I&M		PSO		SWEPCo	
	Gas	Natural Gas	Wind	Natural Gas	Wind	Natural Gas	Wind
Delivery Start Year				(in MWs)			
2026	—	—	73	460	86	150	74
2027	—	160	—	410	86	300	67
2028	203	1,392	—	438	—	472	75
2029	—	996	—	493	—	525	75
2030	—	996	—	568	—	299	75

Large Load Interconnections in Texas

In June 2025, Texas Senate Bill 6 (SB 6) became effective and was signed into law by the Governor of Texas. SB 6 establishes a standardized process for connecting large load customers within ERCOT in a manner intended to support economic development in Texas while reducing the potential for stranded infrastructure costs. The new legislation establishes criteria for new large load interconnections and directs the PUCT to ensure that these large load customers pay a reasonable share of allocated transmission costs. The PUCT continues its rulemaking efforts to implement SB 6, including provisions related to large load interconnection standards, load forecasting, reliability requirements and transmission cost allocation.

AEP Texas has executed Letters of Agreement for approximately 45 gigawatts of incremental load by 2030, including approximately 40 gigawatts of prospective load seeking consideration under ERCOT's Batch Zero process, a one-time transitional interconnection process established by ERCOT and approved by the PUCT in 2026. The ERCOT Batch Zero process is designed to evaluate qualifying large load interconnection requests on a system-wide basis, allocate available transmission capacity, identify necessary transmission upgrades and require financial commitments from participating customers. The process applies primarily to large electric loads of 75 MW or greater and serves as the precursor to ERCOT's future recurring batch interconnection framework. In July 2026, AEP Texas received approximately $2 billion of financial security in the form of cash collateral, corporate or parental guarantees and letters of credit for the 40 gigawatts of prospective load seeking consideration for participation in the Batch Zero process.

ERCOT is expected to identify projects eligible for participation in Batch Zero, while the PUCT is expected to issue additional SB 6 rulemaking guidance in August 2026. ERCOT expects to provide load ramp information to eligible Batch Zero projects in April 2027, enabling large load customers to determine whether to proceed with an interconnection agreement and reserve its electric capacity. These activities are expected to provide greater clarity regarding large load interconnection requirements, transmission infrastructure needs and the timing and scale of future load growth. However, the amount, timing and cost responsibility associated with these prospective large load interconnections remain subject to ongoing ERCOT and PUCT actions.

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 tables summarize the completed and pending base rate case proceedings. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Annual Base Revenue Increase	Previously Approved ROE	Approved ROE	New Rates Effective	
		(in millions)				
APCo/WPCo	West Virginia	$ 91	9.75%	9.75%	August 2025	(a)
SWEPCo	Arkansas	85	9.5%	9.65%	February 2026	(b)
KPCo	Kentucky	55	9.75%	9.75%	March 2026	(c)
OPCo	Ohio	11	9.7%	9.84%	April 2026	

(a) In August 2025, in response to APCo's and WPCo's 2024 West Virginia Base Rate Case filing, the WVPSC originally approved a combined $76 million annual increase in base rates based upon a 9.25% ROE. In February 2026, the WVPSC issued an order on reconsideration of the 2024 West Virginia Base Rate Case, approving a revised ROE of 9.75%, resulting in a $15 million prospective annual increase in base rates, to arrive at an authorized annual increase of $91 million effective February 2026.
(b) See "2025 Arkansas Base Rate Case" section of Note 4 in the 2025 Annual Report for additional information.
(c) In March 2026, KPCo filed a request with the KPSC seeking rehearing on the vegetation management finding in the base case order in addition to certain other denied costs. In April 2026, the KPSC issued an order approving KPCo's request for rehearing.

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Annual Base Revenue Increase Request		Requested ROE
			(in millions)		
SWEPCo	Texas	October 2025	$	95	10.75%
PSO	Oklahoma	January 2026		299	10.5%
APCo	Virginia	May 2026		61	10.5%

Other Significant Regulatory Matters

2025 UTM Filing

In October 2025, AEP Texas submitted its first filing with the PUCT seeking recovery of eligible costs through the UTM. In March 2026, a Texas ALJ issued a PFD recommending partial disallowance of the requested amounts which was based on an interpretation of a later effective date for eligible UTM deferrals. In April 2026, AEP Texas filed responses reflective of the legislative intent of Texas House Bill 5247 (2025). In May 2026, the PUCT Chairman issued a Commissioner Memorandum agreeing with the ALJ's PFD and ordered the PUCT staff to complete a calculation to confirm the final disallowance amount. Completion of the Commission-required calculation and final order are expected in the third quarter of 2026. In conjunction with the Commissioner Memorandum, AEP Texas recognized an unfavorable pretax impact of $23 million in May 2026 primarily attributable to a portion of the deferrals included in the UTM application period.

As of June 30, 2026, AEP Texas had deferred approximately $72 million of eligible costs as a regulatory asset of which $65 million will be included in AEP Texas' next UTM application. Investments included in the UTM and the existing capital tracker filings remain subject to prudency review in the utility's next base rate case proceeding 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.

2026 West Virginia Orders

In March 2026, the WVPSC issued a financing order approving APCo's and WPCo's (the Companies) proposed securitization. In July 2026, the WVPSC approved an overall balance of $2.7 billion of eligible costs for securitization. See "2025 West Virginia Securitization Filing" section of Note 4 for additional information.

In April 2026, the WVPSC issued an order conditionally approving an annual Inflation-Based Rate Adjustment to current base rates of 4% for residential and commercial customers and 2.5% for industrial customers, provided that the Companies: (a) agree with proceeding with securitization, unless otherwise ordered by the WVPSC, (b) agree that the April 2026 Notice of Intent to file a 2026 West Virginia base rate case will be withdrawn and (c) agree that a new base rate case will not be filed prior to June 1, 2027. In April 2026, the Companies agreed to the terms of the Inflation-Based Rate Adjustment described above and filed revised tariff sheets reflecting a $40 million combined annual increase to base rates effective July 1, 2026.

In April 2026, the WVPSC issued an order that adjudicated the Companies' 2024 MRBC surcharge update filing. This order affirms previously approved MRBC revenue requirements and allows the Companies to perform a final true-up in an ENEC filing to recover past MRBC costs that were not reflected in MRBC surcharge rates in a timely manner during the four-year existence of the surcharge. This order also allows the Companies to recognize carrying charges on revised MRBC under-recovery balances starting September 2024 and to recover the updated MRBC under-recovery with carrying charges through current ENEC surcharge rates over a period to be determined in the Companies' 2026 ENEC proceeding. The April 2026 order also noted that collection of the revenue requirement related to inclusion of a stand-alone NOLC deferred tax asset in MRBC rates may be subject to refund, pending the future issuance of a PLR or other guidance by the IRS.

In May 2026, a group of APCo customers submitted an appeal to the West Virginia Intermediate Court of Appeals alleging that the WVPSC erred in its April 2026 order approving: (a) the Inflation-Based Rate Adjustment without adequate findings, evidentiary support or reasoned explanation demonstrating the approval of reasonable rates under WVPSC statutes, (b) a final MRBC true-up without sufficient record support and (c) recovery mechanisms associated with the ENEC, vegetation management, Broadband and securitization-related ratemaking. This appeal was dismissed by the West Virginia Intermediate Court of Appeals for lack of jurisdiction. The group of APCo customers subsequently submitted the appeal to the West Virginia Supreme Court. In July 2026, an intervening party submitted an appeal to the West Virginia Supreme Court regarding the Inflation-Based Rate Adjustment alleging that the WVPSC: (a) failed to carry its burden of proving that the Companies' existing rates were unreasonable and needed to be changed, (b) failed to adequately support its order with evidence of record and (c) violated the due process rights of the intervening party and the customers that it represents. See the "2026 ENEC Update Filing", "West Virginia Modified Rate Base Cost (MRBC) Surcharge Update Filing" and "2025 West Virginia Securitization Filing" sections of Note 4 for additional information.

If any refund liabilities are imposed related to these West Virginia jurisdictional issues, it would reduce future net income and cash flows and impact financial condition.

2025 Virginia Securitization Filing

In May 2026, APCo issued 20-year securitization bonds to finance approximately $1.4 billion of jurisdictional costs, including; (a) $1.2 billion of certain Virginia jurisdictional Property, Plant and Equipment balances for the Amos and Mountaineer Plants, (b) $141 million of Virginia jurisdictional major storm operation and maintenance expenses deferred as Regulatory Assets during the 2024-2025 biennial period and (c) $11 million of up-front financing costs. After issuing the securitization bonds, APCo implemented a rider to recover annual securitization debt financing costs and the Base Rate Reduction (BRR) Rider to credit customers for the recovery of, and return on, the Amos and Mountaineer Plant costs currently included in APCo Virginia base rates.

Indiana Earnings Test

In February 2026, I&M submitted its FAC filing and earnings test evaluation for the period ended November 2025. I&M proposed an over-earnings credit to customers for the earnings test period ending November 2025 of $53 million based on requested modifications to jurisdictional cost allocations to more accurately reflect I&M's cost to serve Indiana retail customers. In June 2026, the IURC issued an order approving the jurisdictional cost allocation modifications and the $53 million over-earnings customer credit. See "Indiana Earnings Test" section of Note 4 for additional information.

Mitchell Plant Cooling Tower CPCN Requests

In February 2026, WPCo and KPCo filed CPCN and cost recovery requests (Mitchell CPCN) with the WVPSC and KPSC, respectively, to obtain the regulatory approvals necessary to: (a) construct a new mechanical draft cooling tower which would allow for continued operation of the 780 MW Mitchell Plant Unit 2 and (b) recover the related estimated investment of $191 million. WPCo and KPCo each own a 50% undivided interest in Mitchell Plant.

In May 2026, intervenors recommended certain modifications to KPCo's cost recovery proposal or that KPCo's Mitchell CPCN request be denied. A hearing was held at the KPSC in July 2026 and a KPSC decision is expected in the fourth quarter of 2026.

In June 2026, the Department of Energy awarded $51 million to support the WPCo and KPCo Mitchell Plant Cooling Tower investment.

In July 2026, WVPSC staff submitted testimony recommending that WPCo's Mitchell CPCN be approved with certain modifications to WPCo's proposed cost recovery, while intervenors submitted testimony that did not offer an opinion as to whether WPCo's Mitchell CPCN should be approved and recommended adjustments to WPCo's cost recovery if WPCo's Mitchell CPCN is approved. A hearing at the WVPSC is scheduled for September 2026 and an order from the WVPSC is expected in the fourth quarter of 2026.

As of June 30, 2026, the net book value of Mitchell Plant Unit 2, before cost of removal and including CWIP and inventory, is estimated to be approximately $643 million ($383 million at WPCo and $260 million at KPCo). If AEP cannot ultimately recover Mitchell Plant Unit 2 costs, it would reduce future net income and cash flows and impact financial condition.

Indiana House Enrolled Act 1002

On February 26, 2026, House Enrolled Act 1002 (HEA 1002) was signed into law in Indiana. Among other things, this law requires Indiana's investor-owned electricity suppliers to petition the IURC for approval of a multi-year rate plan (MYRP). When establishing an electricity supplier's authorized return for its MYRP, Indiana law requires the IURC to consider any changes in risk to the electricity supplier and its customers that may result from implementing the MYRP.

In July 2026, the IURC launched investigations into the risks and changes in those risks to the electricity suppliers and customers in Indiana as a result of the electricity supplier implementing an MYRP. The IURC also launched an investigation into the continued use of trackers or riders by electricity suppliers during MYRPs. Technical conferences to discuss these investigations are scheduled for August 2026.

In July 2026, I&M submitted a notice of intent to file an Indiana MYRP with the IURC no later than September 1, 2026. If I&M is not able to recover its costs to serve Indiana retail customers, including a fair return on investments, it could reduce future net income and cash flows and impact financial condition.

Federal Tax Legislation

In February 2026, the Department of Treasury and the IRS issued additional interim guidance on the application of CAMT, Notice 2026-7. This guidance allows taxpayers to deduct certain tax-deductible repairs when determining adjusted financial statement income for CAMT purposes. This guidance is expected to result in a reduction to applicable Registrants' prior and future CAMT liabilities.

Additional significant guidance from the Department of Treasury and the IRS is expected on the tax provisions in recently enacted legislation. AEP will continue to monitor any issued guidance and evaluate the impact on AEP's future net income, cash flows and financial condition.

Fuel Cell Agreements

In 2025, OPCo signed two contracts totaling approximately 98 MWs for electricity service from fuel cells. The PUCO approved the contracts in May 2025. In September 2025, an intervenor filed a request for rehearing with the Supreme Court of Ohio, opposing the PUCO's approval and claiming that the order was unlawful, anti-competitive, and discriminatory. In June 2026, the appeals were dismissed and the PUCO decisions are now final and non-appealable.

In January 2026, an unregulated subsidiary of AEP executed: (a) an unconditional purchase agreement to acquire a substantial portion of its 1 GW option for solid oxide fuel cells for the development and construction of a fuel cell generation facility for approximately $2.65 billion and (b) a 20 year offtake arrangement with a high investment grade third party customer for 100% of the output of the fuel cell generation facility expected to be located near Cheyenne, Wyoming. The offtake arrangement remains subject to specified conditions, however, in June 2026, the deadline for those conditions was extended by mutual agreement of the parties. Should the revised conditions not be satisfied in December 2026, AEP will be entitled to additional consideration to account for the extended timeline.

Grid Growth Ventures Investment (Applies to AEP)

In 2026, Transource Energy executed agreements to form Grid Growth Ventures, LLC (Grid Growth Ventures) with First Energy Transmission, LLC to participate in PJM's 2025 Regional Transmission Expansion Plan (RTEP) competitive process. In February 2026, PJM selected the projects proposed by Grid Growth Ventures to address forecasted reliability and load growth requirements. The RTEP projects awarded by PJM were estimated to cost approximately $1.2 billion and AEP's share of this investment was estimated to be $600 million. The RTEP projects awarded by PJM will be developed, owned and operated by Grid Ohio Growth EHV Holdings, LLC and Grid Growth Ohio, LLC, subsidiaries of Grid Growth Ventures.

In March 2026, subsidiaries of Grid Growth Ventures, Grid Growth Ohio EHV, LLC and Grid Growth Ohio, LLC, submitted to the FERC a request for acceptance of formula rates for each company, consisting of a formula rate template and implementation protocols, effective May 2026. The filing also requested approval of Federal Power Act Section 219 transmission incentive rate treatments for the projects awarded by PJM to the Grid Growth Ventures subsidiaries. The requested incentive rate treatments include: (a) recovery of abandonment costs if the projects are cancelled for reasons beyond Grid Growth Ventures' control, (b) inclusion of CWIP in rates while the projects are in development, (c) use of hypothetical cap structure of 40% debt and 60% equity until the earlier of either December 31, 2032 or the date all of the projects are in service, after which Grid Growth Ventures will use its actual capital structure and (d) regulatory asset treatment for pre-commercial costs including carrying charges. The filing also proposed depreciation rates, requested a base ROE of 10.8% for both companies and requested authorization to replicate the formula rate and rate incentive treatments for any subsidiaries of Grid Growth Ventures. In July 2026, the FERC issued an order accepting the formula rate, subject to settlement proceedings which will determine the companies' base ROE, cost of debt, formula rate template language and depreciation rates.

Midcontinent Grid Solutions Investment (Applies to AEP)

In 2025, Transource Energy and an affiliate of Berkshire Hathaway Energy formed Midcontinent Grid Solutions, LLC to participate in MISO's 2024 Regional Transmission Expansion Plan competitive process. In January 2026, MISO selected the upgrades proposed by Midcontinent Grid Solutions to address forecasted reliability and load growth requirements. The projects awarded by MISO were estimated to cost approximately $1.2 billion and AEP's share of this investment was estimated to be $500 million. The projects awarded by MISO will be developed, owned and operated by Midcontinent Grid Solutions Wisconsin, LLC (MGS Wisconsin), a subsidiary of Midcontinent Grid Solutions, LLC.

In September 2025, the FERC issued an order accepting the formula rates requested by Midcontinent Grid Solutions, LLC's subsidiary, Midcontinent Grid Solutions Iowa, LLC (MGS Iowa), granting its requested effective date of July 2025 and the following: (a) regulatory asset treatment for pre-commercial and formation costs with carrying charges, (b) a hypothetical capital structure of 60% equity and 40% debt through the date of the company's first transmission project being placed in service, (c) conditional approval of a 50-basis point ROE adder due to participation in an RTO, effective upon the date on which operational control transitions to MISO, and (d) authorization of the company's request to replicate its formula rate and related treatments for future subsidiaries in MISO. The FERC also accepted MGS Iowa's proposed use of a 9.98% base ROE, the MISO regional base ROE effective at the time of the FERC order, and the depreciation rates proposed by the company.

As an affiliate of MGS Iowa, MGS Wisconsin is authorized to replicate MGS Iowa's FERC-approved formula rate. A request was filed in April 2026 and included an additional incentive for the recovery of abandonment costs if the projects are cancelled for reasons beyond MGS Wisconsin's control. In June 2026, the FERC approved MGS Wisconsin's request.

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 in the computation of Excess ADIT regulatory liabilities to be refunded to customers. As of June 30, 2026, there were four jurisdictions awaiting approval and two jurisdictions that have been approved but are subject to refund in their status of transitioning to stand-alone treatment of NOLCs in retail ratemaking. 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, 2026, AEP had NOLC regulatory assets of $97 million, of which $85 million are classified as pending final regulatory approval and $12 million are classified as approved for recovery.

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

AEP sold the Gavin Power Station to Gavin Power LLC and Lighthouse Generation LLC in 2017. Pursuant to the PSA for that transaction, AEP maintained responsibility to complete closure of the 300 acre unlined fly ash reservoir (FAR) pond in accordance with the closure plan approved by the Ohio Environmental Protection Agency and to indemnify the purchasers for that work. In November 2022, 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 FAR is noncompliant with the CCR Rule in multiple respects. The owners of the Gavin Power Station have notified AEP that they believe they are entitled to indemnification for any damages that may result from these claims. 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. See "Claims for Indemnifications Made by Owners of the Gavin Power Station" section of Note 5 for additional information.

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 evolve.

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, 2026, AEP owned generating capacity of approximately 26,500 MWs, of which approximately 10,200 MWs were coal-fired. In April 2024, the Federal EPA announced four major new rules directed at fossil-fuel electric generation facilities. The Federal EPA administration has proposed to revise or repeal portions of those new rules. Management continues to evaluate the impacts of the rules that are currently in effect 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 promoting compliance with all of the rules while meeting AEP's obligations to provide reliable and affordable electricity.

The regulatory requirements and associated costs of compliance 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) regulatory and policy changes implemented by the President and the Federal EPA and (h) other factors.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states and localities implement and administer many of these programs and could impose additional or more stringent requirements. Primary CAA regulatory programs that continue to drive investments in AEP's existing generating units include the following: (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. Certain 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, which in turn may require AEP to make investments in pollution control equipment at existing generating units or change 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. In November 2025, in connection with pending litigation challenging the new standards, the Federal EPA filed a motion asking the court to vacate the stricter $PM_{2.5}$ standard. In June 2026, the United States Court of Appeals for the District of Columbia Circuit denied the request.

If the rule is not vacated by any further legal challenge, states must revise SIPs to attain the new standard. Areas around some of AEP's generating facilities may be deemed nonattainment, which may require additional pollution controls or the implementation of operational constraints. At this time, management cannot reasonably estimate any impacts 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 would require certain 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. The rules implementing the Regional Haze requirements of the CAA have been revisited over time. In January 2026, the Federal EPA published a final rule extending the due date for the next round of Regional Haze SIP submittals by states to July 31, 2031.

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 proposed to approve the Texas Regional Haze SIP. In December 2025, the Federal EPA finalized its approval of the Texas and Oklahoma SIPs. The Federal EPA has recently approved Regional Haze SIP submissions for Ohio and West Virginia, both of which have been appealed by environmental groups. In February 2026, the Federal EPA proposed to approve the Regional Haze SIP for Oklahoma's second implementation period. Management will continue to monitor the rulemakings and litigation and cannot predict the outcome.

New Source Performance Standards

In January 2026, the Federal EPA finalized revisions to the New Source Performance Standards for stationary combustion turbine units that commenced construction, modification or reconstruction after December 13, 2024. The new standards for NO_X require a level of performance equivalent to the application of selective catalytic reduction for large, high-utilization natural gas-fired turbines, but establish various levels of combustion controls as the best system of emission reductions for smaller and lower-utilization turbines. The rule does not change the SO_2 limits applicable to combustion turbines. Management is evaluating the implications of the rule on new combustion turbine projects. Several environmental groups have challenged the rule and in April 2026, AEP and other utilities moved to intervene in support of the Federal EPA in that litigation.

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 February 2023, the Federal EPA Administrator finalized the disapproval of interstate transport SIPs submitted by 19 states, including Texas, addressing the 2015 Ozone NAAQS. 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 ozone season program in states to which the FIP applies. The FIP was the subject of judicial review in the United States Court of Appeals for the District of Columbia Circuit and has since been administratively stayed pending the Supreme Court lifting its June 2024 order staying enforcement of the Good Neighbor Plan, other courts lifting judicial orders staying the Federal EPA SIP disapproval actions as to SIPs submitted by several states, and the Federal EPA taking subsequent rulemaking action consistent with any judicial rulings on the merits. Additionally, in April 2025, the court placed the challenges to the Good Neighbor Plan in abeyance pending further order of the court. The Federal EPA has indicated it intends to propose rulemaking to revise the rule. Management will continue to monitor the 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.

Twenty-seven states, numerous companies, trade associations and others challenged the rule. 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. The court stayed the litigation pending rulemaking by the Federal EPA. In June 2025, the Federal EPA proposed to repeal the GHG emissions standards for fossil-fueled fired electric generating units based on a determination that GHG emissions from power plants do not significantly contribute to air pollution that may endanger public health or the environment. 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. In February 2026, the Federal EPA repealed the 2009 findings of contribution and endangerment for light-duty, medium-duty and heavy-duty vehicles and engines, which determined that GHG emissions from motor vehicles endanger public health and welfare. The Federal EPA also repealed the GHG standards for these vehicle and engine categories as part of that rulemaking. The 2009 Endangerment Finding is the basis of the Federal EPA's authority to regulate GHG emissions under the Clean Air Act. Management is evaluating the Federal EPA's proposed repeal of the 2009 motor vehicle Endangerment Finding and its impact on the Federal EPA's authority to regulate GHG emissions from electric generators. Management cannot predict the outcome of the current litigation or the Federal EPA's proposed action related to the GHG rule or its recent repeal of the Endangerment Finding related to emissions from fossil-fuel fired sources or any litigation that may result. More stringent rules directed at the fossil-fuel fired electric utility industry 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.

AEP is committed to delivering reliable, affordable power and routinely submits IRPs in various regulatory jurisdictions to address future generation needs. Accordingly, AEP continues to focus on developing energy solutions that align with state and federal policy objectives, customer expectations, and reliability requirements. These energy solutions may include a range of generation and energy resources, depending on the needs and priorities of the jurisdictions. AEP remains committed to evaluating and pursuing generation strategies that support reliability, affordability and long-term energy needs where supported by regulators and customers. As an example, APCo and I&M are seeking early site permits to bring small modular reactors to Virginia and Indiana as part of their evaluation of future generation options. AEP's performance will ultimately be driven by the needs and desires of the jurisdictions AEP serves and the company will continue to engage with regulators and policymakers to meet the energy needs while facilitating the delivery of reliable, affordable energy.

MATS Rule

In April 2024, the Federal EPA issued a revised MATS rule for power plants, which 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. In February 2026, the Federal EPA finalized its repeal of the 2024 MATS rule, and the rule's requirements reverted to the 2012 MATS rule emission standards. That repeal has been challenged by various groups. Management will continue to monitor the litigation but does not anticipate any challenges complying with the standards in the now-repealed 2024 rule should its repeal be reversed by the court.

CCR Rule

The Federal EPA's CCR Rule regulates the disposal and beneficial 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 in 2015, the rule applied to active and inactive CCR landfills and surface impoundments at facilities of active electric utility or independent power producers.

In August 2018, the District of Columbia Circuit Court vacated and remanded certain aspects of the 2015 CCR rule, including an exemption for legacy impoundments. Following this, the Federal EPA issued a final rule in August 2020, setting an April 11, 2021 deadline for unlined CCR impoundments to cease waste acceptance and commence closure. This rule permits a facility to request a deadline extension from the Federal EPA if alternative disposal capacity is unavailable or a compliant conversion or a plant retirement is in progress.

In January 2022, the Federal EPA made public statements in the context of a deadline extension request submitted by the Gavin Power Station suggesting more stringent closure requirements for CCR units. See "Claims for Indemnification Made by Owners of the Gavin Power Station" above for additional information. In April 2022, a petition was filed with the District of Columbia Circuit Court of Appeals, arguing that the Federal EPA could not enforce these new purported requirements without proper rulemaking. In June 2024, the District of Columbia Circuit Court dismissed these petitions, finding the statements were not amendments to existing regulations and thus the court lacked jurisdiction.

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"). That rule has been challenged in the District of Columbia Circuit Court. 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. 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. As a result, the litigation challenging the 2024 Legacy Rule is being held in abeyance. In November 2025, the Federal EPA proposed to extend by three years the compliance deadline applicable to certain facilities operating pursuant to alternative closure deadlines for unlined surface impoundments greater than 40 acres. In February 2026, the Federal EPA finalized a rule that provides additional time to meet facility evaluation requirements for identifying CCR management units and to comply with groundwater monitoring provisions. Additionally, this rule makes conforming changes to the remaining CCR management units compliance deadlines. In April 2026, the Federal EPA proposed revisions to the CCR Rule that would rescind requirements for CCR management units, revise requirements for beneficial use of CCR materials, allow expanded reliance on state-approved and other regulatory closures of legacy units, and introduce a new, permit-based, site-specific compliance pathway. The proposal is expected to be finalized by the end of 2026. Management is evaluating the proposal and has participated in the rulemaking process.

Should additional corrective measures like groundwater treatment or ash removal be mandated at any of AEP's coal-fired facilities, AEP could face substantial costs that could materially and adversely affect financial condition, results of operations and cash flows. 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. Several petitions for review have been filed with various federal courts challenging the 2024 ELG rule. SWEPCo also challenged the rule by filing a joint petition with a utility trade association in which AEP participates. The litigation challenging the ELG Rule is being held in abeyance while the new administration evaluates the rule. The Federal EPA has announced plans to reconsider the standards and deadlines established by the 2024 ELG rule.

In December 2025, the Federal EPA issued the Deadline Extension ELG Rule to extend the compliance deadlines in the 2024 ELG Rule by five years as well as to establish a site-specific mechanism for extending compliance deadlines for both the 2020 and 2024 ELG Rules. The Deadline Extension ELG Rule also extended the deadline to commit to cease coal combustion by 2034 from December 31, 2025 to December 31, 2031. Management is evaluating the compliance alternatives in the rule, taking into consideration the requirements of other rules and their combined impacts to operations. Management cannot predict the outcome of the pending litigation or any further rulemaking actions by the Federal EPA related to the ELG rule.

In January 2026, the Federal EPA proposed a rule titled Updating the Water Quality Certification Regulations. Through the proposed rule, the Federal EPA is attempting to clarify the Clean Water Act section 401 certification process for states and tribes. Under section 401, a federal agency cannot conduct any activity that may result in a discharge into waters of the United States without obtaining a permit from a State or authorized tribe in the location of the discharge certifying compliance with applicable water quality requirements. The proposed rule aims to reduce regulatory delays associated with the certification process. Management will monitor the rulemaking for any potential impacts to operations.

The definition of "waters of the United States" has been subject to rulemaking and litigation which has led to inconsistent scope among the states. In November 2025, the Federal EPA and the United States Army Corps of Engineers proposed a revised definition of "waters of the United States" to conform to a decision by the United States Supreme Court. Management will continue to monitor developments in rulemaking 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 regularly 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.

For generating facilities retired or planned for retirement in advance of the retirement date currently authorized for ratemaking purposes, with related accelerated depreciation regulatory assets pending regulatory approval, the table below summarizes the net book value and related regulatory asset balances recorded as of June 30, 2026:

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	$ 53	$ 251	2026	(c)	$ 11
SWEPCo	Pirkey Plant	—	46 (d)	2023	(e)	—
SWEPCo	Welsh Plant, Units 1 and 3	230	249	2028 (f)	(g)	44

(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 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, which the ODEQ has submitted. In anticipation of approval from the Federal EPA, PSO began operating Northeastern Plant, Unit 3 on natural gas in January 2026.
(d) Represents Texas jurisdictional share.
(e) SWEPCo requested recovery of the Texas jurisdictional share of the remaining net book value of the Pirkey Plant in its 2025 Texas Base Rate Case. See the "Regulated Generating Unit that has been Retired and Related Fuel Operations" section of Note 4 for additional information. In January 2026, the FERC issued an order providing recovery of the Pirkey Plant based on blended recovery periods determined by all SWEPCo jurisdictions including Texas.
(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 CCN with the APSC, LPSC and PUCT to convert Welsh Plant, Units 1 and 3 to natural gas in 2028 and 2027, respectively. In February 2026, the APSC issued an order approving the application for a CCN. In July 2026, SWEPCo, PUCT staff and certain intervenors filed an unopposed stipulation and settlement agreement with the PUCT agreeing the application for a CCN should be approved. Additionally, in July 2026, SWEPCo and the LPSC staff filed a joint stipulation and term sheet with the LPSC agreeing the application for a CCN should be approved.
(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 segment provides a comparison of Earnings (Loss) Attributable to AEP Common Shareholders for the three months ended and six months ended June 30, 2026 as compared to the three months ended and six months ended June 30, 2025. 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, 2026 and 2025, see the discussions of Results of Operations by Registrant Subsidiary.

A detailed discussion of AEP's 2025 results of operations by operating segment can be found in Management's Discussion and Analysis of Financial Condition and Results of Operations section included in the 2025 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,	
	2026	2025	2026	2025
	(in millions)			
Vertically Integrated Utilities	$ 284	$ 433	$ 746	$ 757
Transmission and Distribution Utilities	222	224	459	389
AEP Transmission Holdco	225	578	434	813
Generation & Marketing	97	62	172	164
Corporate and Other	(115)	(71)	(224)	(97)
Earnings Attributable to AEP Common Shareholders	$ 713	$ 1,226	$ 1,587	$ 2,026

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.

VERTICALLY INTEGRATED UTILITIES

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
	(in millions of KWhs)			
Retail:				
Residential	6,443	6,372	15,316	15,776
Commercial	7,238	6,297	14,065	12,193
Industrial	8,584	8,595	16,582	16,696
Miscellaneous	567	569	1,101	1,102
Total Retail	22,832	21,833	47,064	45,767
Wholesale (a)	3,550	3,443	7,095	8,234
Total KWhs	26,382	25,276	54,159	54,001

(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,		Six Months Ended June 30,	
	2026	2025	2026	2025
	(in degree days)			
Eastern Region				
Actual – Heating	88	118	1,663	1,735
Normal – Heating	132	133	1,698	1,700
Actual – Cooling	362	374	381	382
Normal – Cooling	352	348	357	352
Western Region				
Actual – Heating	2	21	632	966
Normal – Heating	34	34	911	903
Actual – Cooling	820	772	941	831
Normal – Cooling	742	738	777	771

Vertically Integrated Utilities
Reconciliation of 2025 to 2026 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Earnings Attributable to AEP Common Shareholders	$ 433	$ 757
Changes in Revenues:		
Retail Revenues	168	351
Off-system Sales	(35)	47
Transmission Revenues	(27)	12
Other Revenues	(1)	(3)
Total Change in Revenues	105	407
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	21	21
Other Operation and Maintenance	(74)	(207)
Asset Impairments and Other Related Charges	—	(31)
Depreciation and Amortization	(37)	(81)
Taxes Other Than Income Taxes	(21)	(31)
Other Income	(1)	(2)
Allowance for Equity Funds Used During Construction	5	12
Non-Service Cost Components of Net Periodic Benefit Cost	(12)	(12)
Interest Expense	(62)	(107)
Total Change in Expenses and Other	(181)	(438)
Income Tax Benefit	(73)	20
2026 Earnings Attributable to AEP Common Shareholders	$ 284	$ 746

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Retail Revenues** increased $168 million primarily due to the following:
  - A $179 million increase in base rates and rider revenues.
  - A $60 million increase in weather-normalized revenues primarily in the commercial and industrial classes.

  These increases were partially offset by:
  - A $48 million decrease in fuel revenues primarily due to decreases at APCo and SWEPCo, partially offset by an increase at I&M.
  - A $23 million decrease at SWEPCo due to a probable credit to certain existing wholesale generation customers.
- **Off-system Sales** decreased $35 million primarily due to Rockport Plant, Unit 2 merchant sales and economic hedging activity at I&M.
- **Transmission Revenues** decreased $27 million primarily due to the following:
  - A $56 million decrease due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $32 million increase due to continued transmission investment.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $21 million primarily due to decreases at APCo and SWEPCo, partially offset by increases at I&M and PSO.
- **Other Operation and Maintenance** expenses increased $74 million primarily due to the following:
  - A $41 million increase in generation expenses due to non-outage maintenance, nuclear and renewable energy.
  - A $24 million increase in distribution-related expenses driven by system improvements, forestry, storms, customer driven third-party work and amortization of storm-related regulatory assets.
  - A $10 million increase in employee-related costs.
- **Depreciation and Amortization** expenses increased $37 million primarily due to the following:
  - A $31 million increase due to a higher depreciable base at I&M, PSO and SWEPCo.
  - A $10 million increase at KPCo primarily due to the amortization of securitized assets and PPA rider activity.

  These increases were partially offset by:
  - A $7 million decrease at APCo primarily due to a decrease in depreciation expense at Amos and Mountaineer plants due to the issuance of Virginia securitization bonds.
- **Taxes Other Than Income Taxes** increased $21 million primarily due to the following:
  - A $10 million increase at SWEPCo and I&M primarily due to an increase in property taxes.
  - A $7 million increase at APCo due to higher business and occupation taxes.
- **Allowance for Equity Funds Used During Construction** increased $5 million primarily due to a higher AFUDC base at I&M and SWEPCo and higher equity return rates at I&M.
- **Non-Service Cost Components of Net Periodic Benefit Cost** increased $12 million primarily due to the continued recognition of unfavorable 2022 pension plan asset returns used to calculate the 2026 pension expense.
- **Interest Expense** increased $62 million primarily due to higher long-term debt balances.
- **Income Tax Benefit** decreased $73 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 $7 million decrease due to a decrease in flow-through cost of removal.

  These decreases were partially offset by:
  - A $39 million increase due to an increase in PTCs.
  - A $15 million increase due to a decrease in pretax book income.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Retail Revenues** increased $351 million primarily due to the following:
  - A $371 million increase in base case and rider revenues.
  - A $112 million increase in weather-normalized revenues primarily in the commercial and industrial classes, partially offset by a decrease in the residential class.
  - A $15 million increase due to a decrease in regulatory provisions for refund at I&M.

  These increases were partially offset by:
  - A $104 million decrease in fuel revenues primarily due to decreases at APCo and SWEPCo, partially offset by an increase at I&M.
  - A $27 million decrease in weather-related usage primarily in the residential class driven by a 15% decrease in heating degree days primarily in the western region.
  - A $23 million decrease at SWEPCo due to a probable credit to certain existing wholesale generation customers.
- **Off-system Sales** increased $47 million primarily due to Rockport Plant, Unit 2 merchant sales during Winter Storm Fern in January 2026, partially offset by a decrease in merchant sales and economic hedging activity at I&M.
- **Transmission Revenues** increased $12 million primarily due to the following:
  - A $60 million increase due to continued transmission investment.

  This increase was partially offset by:
  - A $56 million decrease 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 decreased $21 million primarily due to decreases at APCo and SWEPCo, partially offset by increases at I&M and PSO.
- **Other Operation and Maintenance** expenses increased $207 million primarily due to the following:
  - A $74 million increase in generation expenses due to outage and non-outage maintenance, nuclear and renewable energy.
  - A $34 million increase in vegetation management costs.
  - A $32 million increase in employee-related costs.
  - A $25 million increase in distribution-related expenses driven by system improvements, reliability programs, meters and transformers, customer driven third-party work and amortization of storm-related regulatory assets.
  - A $21 million increase in storm expenses.
- **Asset Impairments and Other Related Charges** increased $31 million due to the probable, partial disallowance of the Pirkey Plant net book value in the 2025 Texas Base Rate Case at SWEPCo.
- **Depreciation and Amortization** expenses increased $81 million primarily due to the following:
  - A $52 million increase primarily due to a higher depreciable base at I&M, PSO and SWEPCo.
  - A $10 million increase at KPCo primarily due to the amortization of securitized assets.
  - An $8 million increase due to NOLC-related Excess ADIT deferrals recorded in 2025 and the amortization of these deferrals recorded in 2026 for IURC approved recovery through I&M's Indiana tax rider.
  - A $7 million increase at SWEPCo primarily due to higher over-recovery of costs and allowable return associated with the generation rider.

  These increases were partially offset by:
  - A $6 million decrease at I&M due to Michigan PTC deferral activity.
- **Taxes Other Than Income Taxes** increased $31 million primarily due to the following:
  - A $19 million increase in property taxes at APCo, PSO and SWEPCo.
  - An $8 million increase due to higher business and occupation taxes at APCo.
- **Allowance for Equity Funds Used During Construction** increased $12 million primarily due to a higher AFUDC base and an increase in equity return rates primarily at I&M, SWEPCo and KPCo.
- **Non-Service Cost Components of Net Periodic Benefit Cost** increased $12 million primarily due to the continued recognition of unfavorable 2022 pension plan asset returns used to calculate the 2026 pension expense.
- **Interest Expense** increased $107 million primarily due to the following:
  - An $82 million increase primarily due to higher long-term debt balances.
  - A $10 million increase at PSO and SWEPCo 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 $5 million increase at SWEPCo related to the Texas tax normalization rider amortization.
- **Income Tax Benefit** increased $20 million primarily due to the following:
  - A $112 million increase due to an increase in PTCs.
  - A $24 million increase due to the cumulative true-up of CAMT related to IRS Notice 2026-07 allowing tax repair deductions in the calculation of CAMT.

  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.

TRANSMISSION AND DISTRIBUTION UTILITIES

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
	(in millions of KWhs)			
Retail:				
Residential	6,119	6,299	12,651	13,310
Commercial	12,961	11,042	25,738	20,630
Industrial	8,104	7,048	14,976	13,804
Miscellaneous	171	172	337	344
Total Retail (a)	27,355	24,561	53,702	48,088
Wholesale (b)	256	464	899	1,131
Total KWhs	27,611	25,025	54,601	49,219

(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,	
	2026	2025	2026	2025
	(in degree days)			
Eastern Region				
Actual – Heating	132	170	1,996	2,077
Normal – Heating	172	173	1,991	1,993
Actual – Cooling	309	336	321	342
Normal – Cooling	325	323	328	325
Western Region				
Actual – Heating	1	4	144	296
Normal – Heating	4	4	215	208
Actual – Cooling	900	992	1,124	1,153
Normal – Cooling	919	909	1,035	1,021

Transmission and Distribution Utilities
Reconciliation of 2025 to 2026 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Earnings Attributable to AEP Common Shareholders	$ 224	$ 389
Changes in Revenues:		
Retail Revenues	102	135
Off-system Sales	(7)	18
Transmission Revenues	33	53
Other Revenues	6	10
Total Change in Revenues	134	216
Changes in Expenses and Other:		
Purchased Electricity for Resale	17	13
Purchased Electricity from AEP Affiliates	(1)	(5)
Other Operation and Maintenance	(114)	(117)
Depreciation and Amortization	(9)	(23)
Taxes Other Than Income Taxes	(31)	(26)
Other Income	—	(1)
Allowance for Equity Funds Used During Construction	9	15
Non-Service Cost Components of Net Periodic Benefit Cost	(3)	2
Interest Expense	(18)	(11)
Total Change in Expenses and Other	(150)	(153)
Income Tax Expense	14	8
Equity Earnings of Unconsolidated Subsidiary	—	(1)
2026 Earnings Attributable to AEP Common Shareholders	$ 222	$ 459

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Retail Revenues** increased $102 million primarily due to the following:
  - A $94 million increase in rider revenues in Ohio and Texas.
  - An $11 million increase in weather-normalized revenues primarily in the commercial class in Texas.

  These increases were partially offset by:
  - A $7 million decrease in weather-related usage primarily due to a 9% decrease in cooling degree days in Texas.
- **Off-system Sales** decreased $7 million primarily due to decreased sales of OVEC purchased power driven by lower market prices.
- **Transmission Revenues** increased $33 million primarily due to continued transmission investments in Ohio and Texas.
- **Other Revenues** increased $6 million primarily due to the taxable portion of payments received from customers for large interconnection projects in Texas.

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

- **Purchased Electricity for Resale** expenses decreased $17 million primarily due to the following:
  - A $23 million decrease in OVEC purchased power costs in Ohio.

  This decrease was partially offset by:
  - A $7 million increase in recoverable auction purchases to serve SSO customers in Ohio.
- **Other Operation and Maintenance** expenses increased $114 million primarily due to the following:
  - A $75 million increase primarily due to recoverable PJM transmission expenses in Ohio.
  - An $18 million increase due to the probable, partial disallowance of regulatory assets associated with the UTM deferrals in Texas.
  - A $7 million increase due to recoverable Transmission Cost Recovery Factor expenses in Texas.
  - A $6 million increase primarily due to recoverable distribution vegetation management expenses in Ohio.
- **Depreciation and Amortization** expenses increased $9 million primarily due to a higher depreciable base in Texas.
- **Taxes Other Than Income Taxes** increased $31 million primarily due to the following:
  - A $23 million increase in property taxes in Ohio.
  - A $5 million increase in state excise taxes due to increased billed KWhs in Ohio.
- **Allowance for Equity Funds Used During Construction** increased $9 million primarily due to a higher AFUDC base in Texas.
- **Interest Expense** increased $18 million primarily due to higher long-term debt balances in Texas.
- **Income Tax Expense** decreased $14 million primarily due to Excess ADIT credits refunded to customers as approved in the 2025 Ohio base rate case.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Retail Revenues** increased $135 million primarily due to the following:
  - An $82 million increase in rider revenues in Ohio and Texas.
  - A $60 million increase due to higher prices for purchased power to serve OPCo's SSO customers.
  - A $24 million increase in weather-normalized revenues primarily in the residential class in Ohio and commercial class in Texas.

  These increases were partially offset by:
  - A $40 million decrease in weather-related usage primarily driven by a 6% decrease in cooling degree days in Ohio and a 3% decrease in cooling degree days in Texas.
- **Off-system Sales** increased $18 million primarily due to increased sales of OVEC purchased power driven by higher market prices and volume in Ohio.
- **Transmission Revenues** increased $53 million primarily due to continued transmission investment in Ohio and Texas.
- **Other Revenues** increased $10 million primarily due to the following:
  - A $15 million increase primarily due to the taxable portion of payments received from customers for large interconnection projects in Texas.

  This increase was partially offset by:
  - A $6 million decrease primarily due to lower third-party Legacy Generation Resource Rider revenues related to the recovery of OVEC costs in Ohio.

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

- **Purchased Electricity for Resale** expenses decreased $13 million primarily due to the following:
  - A $44 million decrease as a result of legislation approved in Ohio in 2025 related to the elimination of OPCo's ability to recover from, or refund to, customers the difference between purchased power expenses from OVEC.
  - A $30 million decrease in OVEC purchased power costs in Ohio.

  These decreases were partially offset by:
  - A $58 million increase in recoverable auction purchases to serve SSO customers in Ohio.
- **Purchased Electricity from AEP Affiliates** expenses increased $5 million primarily due to an increase in recoverable purchases to serve SSO customers in Ohio.
- **Other Operation and Maintenance** expenses increased $117 million primarily due to the following:
  - A $50 million increase in recoverable PJM transmission expenses in Ohio.
  - An $18 million increase due to the probable, partial disallowance of regulatory assets associated with the UTM deferrals in Texas.
  - A $15 million increase related to recoverable energy assistance program expenses for qualified Ohio customers.
  - A $14 million increase primarily due to recoverable distribution vegetation management expenses in Ohio.

- An $11 million increase in recoverable transmission storm restoration costs and vegetation management expenses in Ohio.
- **Depreciation and Amortization** expenses increased $23 million due to the following:
  - An $18 million increase due to a higher depreciable base in Texas.
  - A $13 million increase primarily due to the deferral of income tax benefit from Excess ADIT credits to be refunded to customers as approved in the 2025 Ohio base rate case.

  These increases were partially offset by:
  - A $7 million decrease primarily due to the amortization of regulatory liabilities related to Transition Funding customer refunds in Texas.
- **Taxes Other Than Income Taxes** increased $26 million due to the following:
  - An $18 million increase in property taxes in Ohio.
  - A $7 million increase in state excise taxes due to increased billed KWhs in Ohio.
- **Allowance for Equity Funds Used During Construction** increased $15 million primarily due to a higher AFUDC base in Texas.
- **Interest Expense** increased $11 million primarily due to the following:
  - A $24 million increase due to higher long-term debt balances in Texas.

  This increase was partially offset by:
  - An $8 million decrease due to an increase in the debt component of AFUDC in Texas.
  - A $6 million decrease due to the deferral of eligible costs related to the UTM in Texas.
- **Income Tax Expense** decreased $8 million primarily due to the following:
  - An $18 million decrease primarily due to Excess ADIT credits refunded to customers as approved in the 2025 Ohio base rate case.

  This decrease was partially offset by:
  - A $13 million increase due to an increase in pretax book income.

AEP TRANSMISSION HOLDCO

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	June 30,	
	2026	**2025**
	(in millions)	
Plant in Service	$ 18,223	$ 16,496
Construction Work in Progress	2,833	2,371
Accumulated Depreciation and Amortization	2,132	1,810
Total Transmission Property, Net	$ 18,924	$ 17,057

AEP Transmission Holdco
Reconciliation of 2025 to 2026
Earnings Attributable to AEP Members from AEP Transmission Holdco
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Earnings Attributable to AEP Members from AEP Transmission Holdco	$ 578	$ 813
Changes in Transmission Revenues:		
Transmission Revenues	(147)	(91)
Total Change in Transmission Revenues	(147)	(91)
Changes in Expenses and Other:		
Other Operation and Maintenance	(11)	(27)
Depreciation and Amortization	(9)	(24)
Taxes Other Than Income Taxes	(9)	(24)
Interest and Investment Income	—	2
Allowance for Equity Funds Used During Construction	4	4
Non-Service Cost Components of Net Periodic Pension Cost	(1)	(1)
Interest Expense	(9)	(21)
Total Change in Expenses and Other	(35)	(91)
Income Tax Expense	(202)	(202)
Equity Earnings of Unconsolidated Subsidiaries	2	3
Net Income Attributable to Noncontrolling Interests	29	2
2026 Earnings Attributable to AEP Members from AEP Transmission Holdco	$ 225	$ 434

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Transmission Revenues** decreased $147 million primarily due to the following:
  - A $214 million decrease due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $67 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:

- **Other Operation and Maintenance** expenses increased $11 million primarily due to an increase in employee-related costs, vegetation management expenses, affiliated rent expense and other miscellaneous expenses.
- **Depreciation and Amortization** expenses increased $9 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $9 million due to higher property taxes driven by higher transmission investment.
- **Interest Expense** increased $9 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $202 million primarily due to the following:
  - A $254 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.

  This increase was partially offset by:
  - A $38 million decrease due to a decrease in pretax book income.
- **Net Income Attributable to Noncontrolling Interests** decreased $29 million primarily due to the following:
  - A $54 million decrease due to higher 2025 earnings for Midwest Transmission Holdings due to the impact of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $25 million increase primarily due to the Midwest Transmission Holdings noncontrolling interest transaction that closed in June 2025.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Transmission Revenues** decreased $91 million primarily due to the following:
  - A $214 million decrease due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $123 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:

- **Other Operation and Maintenance** expenses increased $27 million primarily due to an increase in employee-related costs, vegetation management expenses, affiliated rent expense and other miscellaneous expenses.
- **Depreciation and Amortization** expenses increased $24 million due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $24 million primarily due to higher property taxes driven by increased investment.
- **Interest Expense** increased $21 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $202 million primarily due to the following:
  - A $254 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.

  This increase was partially offset by:
  - A $38 million decrease due to a decrease in pretax book income.
- **Net Income Attributable to Noncontrolling Interests** decreased $2 million primarily due to the following:
  - A $54 million decrease due to higher 2025 earnings for Midwest Transmission Holdings due to the impact 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 primarily due to the Midwest Transmission Holdings noncontrolling interest transaction that closed in June 2025.

GENERATION & MARKETING

Reconciliation of 2025 to 2026 Earnings Attributable to AEP Common Shareholders
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Earnings Attributable to AEP Common Shareholders	$ 62	$ 164
Changes in Revenues:		
Retail, Trading and Marketing	94	268
Merchant Generation	35	44
Other Revenues	14	36
Total Change in Revenues	143	348
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(95)	(366)
Other Operation and Maintenance	(6)	15
Depreciation and Amortization	—	(1)
Interest and Investment Income	4	9
Non-Service Cost Components of Net Periodic Benefit Cost	—	(1)
Interest Expense	—	1
Total Change in Expenses and Other	(97)	(343)
Income Tax Expense	(11)	3
2026 Earnings Attributable to AEP Common Shareholders	$ 97	$ 172

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Retail, Trading and Marketing** increased $94 million primarily due to higher market prices in 2026 and MTM hedging gains.
- **Merchant Generation** increased $35 million primarily due to higher realized prices in 2026.
- **Other Revenues** increased $14 million primarily due to continued progress on projects in 2026.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $95 million primarily due to an increase in energy costs in 2026.
- **Other Operation and Maintenance** expenses increased $6 million primarily due to lower renewable contract restructuring and termination proceeds in 2026.
- **Income Tax Expense** increased $11 million primarily due to an increase in pretax book income.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Retail, Trading and Marketing** increased $268 million primarily due to higher market prices in 2026, partially offset by reduced MTM hedging gains.
- **Merchant Generation** increased $44 million primarily due to higher realized prices in 2026.
- **Other Revenues** increased $36 million primarily due to continued progress on projects in 2026.

Expenses and Other changed between years as follows:

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $366 million primarily due to an increase in energy costs in 2026.
- **Other Operation and Maintenance** expenses decreased $15 million primarily due to renewable contract restructuring and termination proceeds in 2026.
- **Interest and Investment Income** increased $9 million primarily due to an increase in interest income due to higher advances to affiliates.

CORPORATE AND OTHER

Second Quarter of 2026 Compared to Second Quarter of 2025

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $71 million in 2025 to a loss of $115 million in 2026 primarily due to:

- A $31 million decrease in Income Tax Benefit primarily due to the following:
  - A $25 million decrease due to an increase in state taxes.
  - A $5 million decrease due to a decrease in PTCs.
- A $19 million increase in interest expense primarily due to higher long-term debt balances.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

Earnings Attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $97 million in 2025 to a loss of $224 million in 2026 primarily due to:

- A $51 million decrease in Income Tax Benefit primarily due to the following:
  - A $37 million decrease due to a decrease in PTCs.
  - A $26 million decrease due to an increase in state taxes.

  These decreases were partially offset by:
  - A $16 million increase due to a decrease in pretax book income.
- A $38 million increase in interest expense due to higher long-term debt balances.
- An $11 million decrease in the recognition of deferred revenues on completed contracts.

AEP CONSOLIDATED INCOME TAXES

Second Quarter of 2026 Compared to Second Quarter of 2025

Income Tax Expense increased $303 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 $21 million increase due to an increase in state taxes.

These increases were partially offset by:

- A $50 million decrease due to a decrease in pretax book income.
- A $34 million decrease due to an increase in PTCs.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

Income Tax Expense increased $222 million primarily due to the following:

- 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 $20 million increase due to an increase in state taxes.

These increases were partially offset by:

- A $75 million decrease due to an increase in PTCs.
- A $46 million decrease due to a decrease in pretax book income.
- A $24 million decrease due to the cumulative true-up of CAMT related to IRS Notice 2026-07 allowing tax repair deductions in the calculation of CAMT.
- A $14 million decrease due to an increase in amortization of Excess ADIT.

FINANCIAL CONDITION

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

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	June 30, 2026		December 31, 2025	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 50,808	59.0 %	$ 47,322	58.4 %
Short-term Debt	2,028	2.4	1,508	1.9
Total Debt	52,836	61.4	48,830	60.3
AEP Common Equity	32,079	37.2	31,138	38.4
Noncontrolling Interests	1,210	1.4	1,080	1.3
Total Debt and Equity Capitalization	$ 86,125	100.0 %	$ 81,048	100.0 %

AEP's ratio of debt-to-total capital increased from 60.3% to 61.4% as of December 31, 2025 and June 30, 2026, respectively, primarily due to an increase in long-term debt to support AEP's 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 for the foreseeable future. As of June 30, 2026, AEP had $8 billion of revolving credit facilities to support its commercial paper program. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, long-term asset securitizations, leasing agreements, hybrid securities or common stock. AEP and its utilities finance its operations with commercial paper and other variable rate instruments that are subject to fluctuations in interest rates. To the extent that there is an increase in interest rates, it could reduce future net income and cash flows and impact financial condition. In addition, 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.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of June 30, 2026, available liquidity was approximately $7.3 billion as illustrated in the table below:

	Amount	Maturity
Commercial Paper:	(in millions)	
Revolving Credit Facility	$ 6,500	April 2031
Revolving Credit Facility	1,500	April 2029
Cash and Cash Equivalents	375	
Total Liquidity Sources	8,375	
Less: AEP Commercial Paper Outstanding	1,125	
Net Available Liquidity	$ 7,250	

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 2026 was $2.1 billion. The weighted-average interest rate for AEP's commercial paper for the six months ended June 30, 2026 was 3.93%.

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 seven uncommitted facilities totaling $850 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of June 30, 2026 was $535 million with maturities ranging from July 2026 to June 2027.

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 2027. As of June 30, 2026, 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, 2026, this contractually defined percentage was 52.4%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $100 million, would cause an event of default under these credit agreements. This condition also applies, at the more restrictive level of $50 million of debt outstanding, in a majority of AEP's non-exchange-traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange-traded commodity contracts would not cause an event of default under its credit agreements.

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

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

ATM Program

In November 2025, AEP filed a prospectus supplement under which it may sell up to $3.5 billion of its common stock through an ATM program. In the first quarter of 2026, 2 million shares of common stock were issued for $264 million in net proceeds. In addition to these issuances and sales of shares of common stock, AEP also may use the ATM program to enter into forward sale agreements.

See "Forward Equity Agreements" section of Note 12 for additional information regarding shares issued or expected to be issued under forward sale agreements.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.95 per share in July 2026. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends. Management does not believe these restrictions will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 12 for additional information.

Credit Ratings

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

CASH FLOW

AEP relies primarily on cash flows from operations, debt issuances, issuances of common stock 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,	
	2026	2025
	(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 268	$ 246
Net Cash Flows from Operating Activities	3,421	2,671
Net Cash Flows Used for Investing Activities	(6,602)	(5,347)
Net Cash Flows from Financing Activities	3,360	2,709
Net Increase in Cash, Cash Equivalents and Restricted Cash	179	33
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 447	$ 279

Operating Activities

	Six Months Ended June 30,	
	2026	2025
	(in millions)	
Net Income	$ 1,650	$ 2,091
Non-Cash Adjustments to Net Income (a)	2,035	1,519
Mark-to-Market of Risk Management Contracts	(123)	(241)
Pension Contributions to Qualified Plan Trust	—	(95)
Property Taxes	238	241
Deferred Fuel Over/Under-Recovery, Net	31	(41)
Change in Other Noncurrent Assets	(628)	(440)
Change in Other Noncurrent Liabilities	581	41
Change in Certain Components of Working Capital	(363)	(404)
Net Cash Flows from Operating Activities	$ 3,421	$ 2,671

(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 increased by $750 million primarily due to the following:

- A $540 million increase in cash from Change in Other Noncurrent Liabilities. This increase is primarily due to an increase in security deposits held for customers and changes in regulatory liabilities driven by timing differences in refunds to customers under rate rider mechanisms.
- A $95 million increase in cash due to a discretionary contribution to the qualified pension plan made in 2025. See Note 7 - Benefit Plans for additional information.
- A $75 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.
- A $24 million increase in cash due to changes in risk management contract collateral positions.

Investing Activities

	Six Months Ended June 30,	
	2026	2025
	(in millions)	
Construction Expenditures	$ (5,606)	$ (4,020)
Acquisitions of Generation Facilities	(1,315)	(1,359)
Acquisitions of Nuclear Fuel	(51)	(45)
Contribution in Aid of Construction Advances	425	106
Other	(55)	(29)
Net Cash Flows Used for Investing Activities	$ (6,602)	$ (5,347)

Net Cash Flows Used for Investing Activities increased by $1.3 billion primarily due to the following:

- A $1.6 billion increase in Construction Expenditures primarily due to increases in Transmission and Distribution Utilities of $698 million and Vertically Integrated Utilities of $506 million.

This increase was partially offset by:

- A $319 million decrease due to higher contributions in aid of construction primarily due to increases in Transmission and Distribution Utilities of $208 million and AEP Transmission Holdco of $115 million.

Financing Activities

	Six Months Ended June 30,	
	2026	2025
	(in millions)	
Issuance of Common Stock	$ 405	$ 132
Issuance/Retirement of Debt, Net	3,987	817
Proceeds from the Midwest Transmission Holdings Noncontrolling Interest Transaction, Net of Transaction Costs	—	2,783
Dividends Paid on Common Stock	(1,039)	(999)
Other	7	(24)
Net Cash Flows from Financing Activities	$ 3,360	$ 2,709

Net Cash Flows from Financing Activities increased by $651 million primarily due to the following:

- A $1.9 billion increase in issuances of long-term debt. See Note 12 - Financing Activities for additional information.
- A $1.5 billion increase due to changes in short-term debt.
- A $273 million increase in issuances of common stock primarily under AEP's ATM Program. See Note 12 - Financing Activities for additional information.

These increases in cash were partially offset by:

- A $2.8 billion decrease due to proceeds from the 2025 Midwest Transmission Holdings Noncontrolling Interest transaction. See "Noncontrolling Interest in Midwest Transmission Holdings" section of Note 6 for additional information.
- A $254 million increase in retirements of long-term debt. See Note 12 - Financing Activities for additional information.

See the "Financing Activities Subsequent Events" section of Note 12 for Long-term debt and other securities issued, retired and principal payments made after June 30, 2026 through July 30, 2026, the date that the second quarter Form 10-Q was filed.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $12.8 billion of capital expenditures in 2026. For the four-year period, 2027 through 2030, management forecasts capital expenditures of $65.1 billion. Management's forecasted capital expenditures reflect planned investments for transmission infrastructure and new generation resources to support existing customers and 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, technology advancements, inflation and the ability to access capital. Management has funded, or expects to fund, these capital expenditures through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged.

The 2026-2030 estimated capital expenditures by Business Segment are as follows:

Segment	2026-2030 Budgeted Capital Expenditures	
	(in millions)	
Vertically Integrated Utilities	$	40,879
Transmission and Distribution Utilities		22,537
AEP Transmission Holdco		12,855
Generation & Marketing		111
Corporate and Other		1,555
Total	$	77,937

SIGNIFICANT CASH REQUIREMENTS

A summary of significant cash requirements is included in the 2025 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 2025 Annual Report for a discussion of the estimates and judgments required for regulatory accounting, revenue recognition, derivative instruments, the valuation of long-lived assets, the accounting for pension and other postretirement benefits and asset retirement obligations.

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

For a detailed discussion of AEP's market risks, see "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A of AEP's Annual Report on Form 10-K for the year ended December 31, 2025. During the six months ended June 30, 2026, there were no material changes to disclosures about market risk, inclusive of credit risk, value at risk associated with risk management contracts and interest rate risk. See Note 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to risk management contracts.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions, except per-share and share amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
REVENUES				
Vertically Integrated Utilities	$ 3,050	$ 2,934	$ 6,415	$ 6,020
Transmission and Distribution Utilities	1,568	1,443	3,162	2,958
Generation & Marketing	693	552	1,624	1,282
Other Revenues	134	158	264	290
TOTAL REVENUES	5,445	5,087	11,465	10,550
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,603	1,541	3,721	3,394
Other Operation	814	538	1,564	1,290
Maintenance	444	390	855	709
Asset Impairments and Other Related Charges	—	—	31	—
Depreciation and Amortization	910	854	1,817	1,687
Taxes Other Than Income Taxes	427	365	870	787
TOTAL EXPENSES	4,198	3,688	8,858	7,867
OPERATING INCOME	1,247	1,399	2,607	2,683
Other Income (Expense):				
Other Income	14	15	20	23
Allowance for Equity Funds Used During Construction	75	57	145	114
Non-Service Cost Components of Net Periodic Benefit Cost	19	35	57	70
Interest Expense	(585)	(489)	(1,137)	(984)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	770	1,017	1,692	1,906
Income Tax Expense (Benefit)	52	(251)	96	(126)
Equity Earnings of Unconsolidated Subsidiaries	29	21	54	59
NET INCOME	747	1,289	1,650	2,091
Net Income Attributable to Noncontrolling Interests	34	63	63	65
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 713	$ 1,226	$ 1,587	$ 2,026
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	544,163,341	534,283,554	543,127,062	533,839,985
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.31	$ 2.29	$ 2.92	$ 3.80
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	550,628,111	536,425,635	548,846,865	535,547,029
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1.30	$ 2.29	$ 2.89	$ 3.78

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
Net Income	$ 747	$ 1,289	$ 1,650	$ 2,091
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $6 and $(9) for the Three Months Ended June 30, 2026 and 2025, Respectively, and $2 and $(3) for the Six Months Ended June 30, 2026 and 2025, Respectively	22	(33)	7	(10)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $1 and $0 for the Three Months Ended June 30, 2026 and 2025, Respectively, and $1 and $0 for the Six Months Ended June 30, 2026 and 2025, Respectively	1	—	2	1
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	23	(33)	9	(9)
TOTAL COMPREHENSIVE INCOME	770	1,256	1,659	2,082
Total Comprehensive Income Attributable To Noncontrolling Interests	34	63	63	65
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 736	$ 1,193	$ 1,596	$ 2,017

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2026 and 2025
(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, 2024	534	$ 3,472	$ 9,606	$ 13,869	$ (3)	$ 42	$ 26,986
Issuance of Common Stock	1	7	68				75
Common Stock Dividends				(500) (a)		(1)	(501)
Other Changes in Equity			(22)				(22)
Net Income				800		2	802
Other Comprehensive Income					24		24
TOTAL EQUITY – MARCH 31, 2025	535	3,479	9,652	14,169	21	43	27,364
Issuance of Common Stock	1	4	53				57
Common Stock Dividends				(499) (a)		(1)	(500)
Other Changes in Equity			8				8
Midwest Transmission Holdings Noncontrolling Interest Transaction			1,791			992	2,783
Net Income				1,226		63	1,289
Other Comprehensive Loss					(33)		(33)
TOTAL EQUITY – JUNE 30, 2025	536	$ 3,483	$ 11,504	$ 14,896	$ (12)	$ 1,097	$ 30,968
TOTAL EQUITY – DECEMBER 31, 2025	542	$ 3,523	$ 12,138	$ 15,441	$ 36	$ 1,080	$ 32,218
Issuance of Common Stock	3	21	337				358
Capital Contributions from Noncontrolling Interest						96	96
Common Stock Dividends				(520) (b)			(520)
Dividends Paid to Noncontrolling Interest						(35)	(35)
Other Changes in Equity			(28)				(28)
Net Income				874		29	903
Other Comprehensive Loss					(14)		(14)
TOTAL EQUITY – MARCH 31, 2026	545	3,544	12,447	15,795	22	1,170	32,978
Issuance of Common Stock	1	2	45				47
Capital Contributions from Noncontrolling Interest						60	60
Common Stock Dividends				(519) (b)			(519)
Dividends Paid to Noncontrolling Interest						(54)	(54)
Other Changes in Equity			7				7
Net Income				713		34	747
Other Comprehensive Income					23		23
TOTAL EQUITY – JUNE 30, 2026	546	$ 3,546	$ 12,499	$ 15,989	$ 45	$ 1,210	$ 33,289

(a) Cash dividends declared per AEP common share were $0.93.
(b) Cash dividends declared per AEP common share were $0.95.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT ASSETS		
Cash and Cash Equivalents	$ 375	$ 197
Restricted Cash (June 30, 2026 and December 31, 2025 Amounts Include $72 and $71, Respectively, Related to Restoration Funding, Appalachian Consumer Rate Relief Funding, Appalachian Recovery Funding, Storm Recovery Funding and Cost Recovery Funding)	72	71
Other Temporary Investments (June 30, 2026 and December 31, 2025 Amounts Include $220 and $209, Respectively, Related to EIS)	228	220
Accounts Receivable:		
Customers	1,266	1,166
Accrued Unbilled Revenues	360	421
Pledged Accounts Receivable – AEP Credit	1,396	1,272
Miscellaneous	70	60
Allowance for Credit Losses	(57)	(52)
Total Accounts Receivable	3,035	2,867
Fuel	606	576
Materials and Supplies	1,183	1,046
Risk Management Assets	533	352
Accrued Tax Benefits	278	85
Regulatory Asset for Under-Recovered Fuel Costs	525	426
Prepayments and Other Current Assets	299	212
TOTAL CURRENT ASSETS	7,134	6,052
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	26,707	28,388
Transmission	43,764	42,557
Distribution	34,626	33,364
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	9,406	8,635
Construction Work in Progress	9,696	7,635
Total Property, Plant and Equipment	124,199	120,579
Accumulated Depreciation and Amortization	27,526	28,205
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	96,673	92,374
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,021	4,804
Securitized Assets	2,252	933
Spent Nuclear Fuel and Decommissioning Trusts	5,241	4,916
Goodwill	53	53
Long-term Risk Management Assets	235	265
Operating Lease Assets	642	661
Deferred Charges and Other Noncurrent Assets	4,319	4,402
TOTAL OTHER NONCURRENT ASSETS	17,763	16,034
TOTAL ASSETS	$ 121,570	$ 114,460

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2026 and December 31, 2025
(in millions, except per-share and share amounts)
(Unaudited)

			June 30, 2026	December 31, 2025
CURRENT LIABILITIES				
Accounts Payable			$ 3,969	$ 3,429
Short-term Debt:				
Securitized Debt for Receivables – AEP Credit			900	900
Other Short-term Debt			1,128	608
Total Short-term Debt			2,028	1,508
Long-term Debt Due Within One Year (June 30, 2026 and December 31, 2025 Amounts Include $215 and $207, Respectively, Related to DCC Fuel, Restoration Funding, Appalachian Consumer Rate Relief Funding, Appalachian Recovery Funding, Storm Recovery Funding, Transource Energy and Cost Recovery Funding)			2,821	3,194
Risk Management Liabilities			152	132
Customer Deposits			515	507
Accrued Taxes			1,799	2,002
Accrued Interest			590	544
Obligations Under Operating Leases			94	100
Other Current Liabilities			2,187	1,898
TOTAL CURRENT LIABILITIES			14,155	13,314
NONCURRENT LIABILITIES				
Long-term Debt (June 30, 2026 and December 31, 2025 Amounts Include $2,566 and $1,294, Respectively, Related to DCC Fuel, Restoration Funding, Appalachian Consumer Rate Relief Funding, Appalachian Recovery Funding, Storm Recovery Funding, Transource Energy and Cost Recovery Funding)			47,987	44,128
Long-term Risk Management Liabilities			175	178
Deferred Income Taxes			11,485	10,951
Regulatory Liabilities and Deferred Investment Tax Credits			8,622	8,362
Asset Retirement Obligations			3,645	3,556
Employee Benefits and Pension Obligations			267	232
Obligations Under Operating Leases			568	578
Deferred Credits and Other Noncurrent Liabilities			1,313	905
TOTAL NONCURRENT LIABILITIES			74,062	68,890
TOTAL LIABILITIES			88,217	82,204
Rate Matters (Note 4)				
Commitments, Guarantees and Contingencies (Note 5)				
Contingently Redeemable Performance Share Awards			64	38
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
	2026	**2025**		
Shares Authorized	900,000,000	600,000,000		
Shares Issued	545,549,444	542,048,288		
(1,186,815 Shares were Held in Treasury as of June 30, 2026 and December 31, 2025, Respectively)			3,546	3,523
Paid-in Capital			12,499	12,138
Retained Earnings			15,989	15,441
Accumulated Other Comprehensive Income (Loss)			45	36
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			32,079	31,138
Noncontrolling Interests			1,210	1,080
TOTAL EQUITY			33,289	32,218
TOTAL LIABILITIES AND EQUITY			$ 121,570	$ 114,460

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
OPERATING ACTIVITIES		
Net Income	$ 1,650	$ 2,091
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,817	1,687
Deferred Income Taxes	332	(54)
Asset Impairments and Other Related Charges	31	—
Allowance for Equity Funds Used During Construction	(145)	(114)
Mark-to-Market of Risk Management Contracts	(123)	(241)
Pension Contributions to Qualified Plan Trust	—	(95)
Property Taxes	238	241
Deferred Fuel Over/Under-Recovery, Net	31	(41)
Change in Other Noncurrent Assets	(628)	(440)
Change in Other Noncurrent Liabilities	581	41
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(62)	(176)
Fuel, Materials and Supplies	(162)	114
Accounts Payable	408	287
Accrued Taxes, Net	(397)	(469)
Other Current Assets	(27)	11
Other Current Liabilities	(123)	(171)
Net Cash Flows from Operating Activities	3,421	2,671
INVESTING ACTIVITIES		
Construction Expenditures	(5,606)	(4,020)
Purchases of Investment Securities	(1,264)	(1,337)
Sales of Investment Securities	1,216	1,311
Acquisitions of Generation Facilities	(1,315)	(1,359)
Acquisitions of Nuclear Fuel	(51)	(45)
Contribution in Aid of Construction Advances	425	106
Other Investing Activities	(7)	(3)
Net Cash Flows Used for Investing Activities	(6,602)	(5,347)
FINANCING ACTIVITIES		
Capital Contribution from Noncontrolling Interest	156	—
Issuance of Common Stock	405	132
Issuance of Long-term Debt	5,045	3,163
Issuance of Short-term Debt with Original Maturities greater than 90 Days	—	320
Change in Short-term Debt with Original Maturities less than 90 Days, Net	520	(764)
Retirement of Long-term Debt	(1,578)	(1,324)
Redemption of Short-term Debt with Original Maturities Greater than 90 Days	—	(578)
Proceeds from the Midwest Transmission Holdings Noncontrolling Interest Transaction, Net of Transaction Costs	—	2,783
Dividends Paid on Common Stock	(1,039)	(999)
Dividends Paid to Noncontrolling Interest	(89)	(2)
Other Financing Activities	(60)	(22)
Net Cash Flows from Financing Activities	3,360	2,709
Net Increase in Cash, Cash Equivalents and Restricted Cash	179	33
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	268	246
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 447	$ 279

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
	(in millions of KWhs)			
Retail:				
Residential	3,167	3,275	5,698	6,191
Commercial	4,710	4,719	9,768	8,818
Industrial	4,377	3,300	7,871	6,670
Miscellaneous	148	147	286	291
Total Retail	12,402	11,441	23,623	21,970

Summary of Heating and Cooling Degree Days

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
	(in degree days)			
Actual – Heating	1	4	144	296
Normal – Heating	4	4	215	208
Actual – Cooling	900	992	1,124	1,153
Normal – Cooling	919	909	1,035	1,021

AEP Texas Inc. and Subsidiaries
Reconciliation of 2025 to 2026
Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Net Income	$ 121	$ 223
Changes in Revenues:		
Retail Revenues	14	(7)
Transmission Revenues	20	33
Other Revenues	6	15
Total Change in Revenues	40	41
Changes in Expenses and Other:		
Other Operation and Maintenance	(26)	(22)
Depreciation and Amortization	(13)	(9)
Taxes Other Than Income Taxes	(2)	—
Allowance for Equity Funds Used During Construction	8	15
Non-Service Cost Components of Net Periodic Benefit Cost	1	1
Interest Expense	(17)	(10)
Total Change in Expenses and Other	(49)	(25)
Income Tax Expense	1	(6)
2026 Net Income	$ 113	$ 233

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Retail Revenues** increased $14 million primarily due to the following:
  - A $16 million increase in rider revenues.
  - An $11 million increase in weather-normalized revenues primarily in the commercial class.

  These increases were partially offset by:
  - A $7 million decrease in weather-related usage primarily due to a 9% decrease in cooling degree days.
  - A $4 million regulatory refund provision established due to the probable, partial disallowance of UTM deferrals.
- **Transmission Revenues** increased $20 million primarily due to the following:
  - A $21 million increase in transmission investments.

  This increase was partially offset by:
  - A $4 million regulatory refund provision established due to the probable, partial disallowance of UTM deferrals.
- **Other Revenues** increased $6 million primarily due to the taxable portion of payments received from customers for large interconnection projects.

Expenses and Other changed between years as follows:

- **Other Operation and Maintenance** expenses increased $26 million primarily due to the following:
  - An $18 million increase due to the probable, partial disallowance of regulatory assets associated with the UTM deferrals.
  - A $7 million increase due to recoverable Transmission Cost Recovery Factor expenses.
- **Depreciation and Amortization** expenses increased $13 million primarily due to a higher depreciable base.
- **Allowance for Equity Funds Used During Construction** increased $8 million primarily due to a higher AFUDC base.
- **Interest Expense** increased $17 million primarily due to higher long-term debt balances.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Retail Revenues** decreased $7 million primarily due to the following:
  - A $20 million decrease in weather-related usage primarily due to a 3% decrease in cooling degree days.
  - A $7 million decrease due to Transition Funding customer refunds.
  - A $4 million regulatory refund provision established due to the probable, partial disallowance of UTM deferrals.

  These decreases were partially offset by:
  - A $14 million increase in weather-normalized revenues primarily in the residential and commercial classes.
  - A $7 million increase in rider revenues.
- **Transmission Revenues** increased $33 million primarily due to the following:
  - A $34 million increase in transmission investments.

  This increase was partially offset by:
  - A $4 million regulatory refund provision established due to the probable, partial disallowance of UTM deferrals.
- **Other Revenues** increased $15 million primarily due to the taxable portion of payments received from customers for large interconnection projects.

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

- **Other Operation and Maintenance** expenses increased $22 million primarily due to an $18 million increase due to the probable, partial disallowance of regulatory assets associated with the UTM deferrals.
- **Depreciation and Amortization** expenses increased $9 million primarily due to the following:
  - An $18 million increase due to a higher depreciable base.

  This increase was partially offset by:
  - A $7 million decrease primarily due to the amortization of regulatory liabilities related to Transition Funding customer refunds.
  - A $3 million decrease due to the deferral of eligible costs related to the UTM.
- **Allowance for Equity Funds Used During Construction** increased $15 million primarily due to a higher AFUDC base.
- **Interest Expense** increased $10 million primarily due to the following:
  - A $24 million increase due to higher long-term debt balances.

  This increase was partially offset by:
  - An $8 million decrease due to an increase in the debt component of AFUDC.
  - A $6 million decrease due to the deferral of eligible costs related to the UTM.
- **Income Tax Expense** increased $6 million primarily due to the following:
  - A $4 million increase due to a decrease in amortization of Excess ADIT.
  - A $3 million increase due to an increase in pretax book income.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
REVENUES				
Electric Transmission and Distribution	$ 560	$ 528	$ 1,073	$ 1,048
Sales to AEP Affiliates	1	2	3	3
Other Revenues	10	1	19	3
TOTAL REVENUES	571	531	1,095	1,054
EXPENSES				
Other Operation	194	164	356	330
Maintenance	27	31	51	55
Depreciation and Amortization	120	107	225	216
Taxes Other Than Income Taxes	40	38	85	85
TOTAL EXPENSES	381	340	717	686
OPERATING INCOME	190	191	378	368
Other Income (Expense):				
Interest Income	1	1	1	1
Allowance for Equity Funds Used During Construction	20	12	39	24
Non-Service Cost Components of Net Periodic Benefit Cost	6	5	12	11
Interest Expense	(78)	(61)	(144)	(134)
INCOME BEFORE INCOME TAX EXPENSE	139	148	286	270
Income Tax Expense	26	27	53	47
NET INCOME	$ 113	$ 121	$ 233	$ 223

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
Net Income	$ 113	$ 121	$ 233	$ 223
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for Three Months Ended June 30, 2026 and 2025, Respectively, and $0 and $0 for the Six Months Ended June 30, 2026 and 2025, Respectively	—	—	—	(1)
TOTAL COMPREHENSIVE INCOME	$ 113	$ 121	$ 233	$ 222

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	$ 2,093	$ 2,795	$ (3)	$ 4,885
Net Income		102		102
Other Comprehensive Loss			(1)	(1)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2025	2,093	2,897	(4)	4,986
Capital Contribution from Parent	250			250
Net Income		121		121
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2025	$ 2,343	$ 3,018	$ (4)	$ 5,357
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2025	$ 2,546	$ 3,283	$ (3)	$ 5,826
Net Income		120		120
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2026	2,546	3,403	(3)	5,946
Capital Contribution from Parent	1			1
Net Income		113		113
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2026	$ 2,547	$ 3,516	$ (3)	$ 6,060

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT ASSETS		
Restricted Cash (June 30, 2026 and December 31, 2025 Amounts Include $13 and $14, Respectively, Related to Restoration Funding)	$ 13	$ 14
Advances to Affiliates	7	7
Accounts Receivable:		
Customers	244	189
Affiliated Companies	11	15
Accrued Unbilled Revenues	118	101
Total Accounts Receivable	373	305
Materials and Supplies	225	168
Prepayments and Other Current Assets	31	15
TOTAL CURRENT ASSETS	649	509
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	8,458	8,229
Distribution	7,200	6,835
Other Property, Plant and Equipment	1,282	1,239
Construction Work in Progress	2,233	1,766
Total Property, Plant and Equipment	19,173	18,069
Accumulated Depreciation and Amortization	2,260	2,205
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	16,913	15,864
OTHER NONCURRENT ASSETS		
Regulatory Assets	444	402
Securitized Assets (June 30, 2026 and December 31, 2025 Amounts Include $82 and $94, Respectively, Related to Restoration Funding)	82	94
Operating Lease Assets	49	52
Deferred Charges and Other Noncurrent Assets	222	154
TOTAL OTHER NONCURRENT ASSETS	797	702
TOTAL ASSETS	$ 18,359	$ 17,075

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT LIABILITIES		
Advances from Affiliates	$ 354	$ 188
Accounts Payable:		
General	595	652
Affiliated Companies	43	60
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2026 and December 31, 2025 Amounts Include $25 and $25, Respectively, Related to Restoration Funding)	25	75
Accrued Taxes	151	118
Accrued Interest	73	64
Security Deposits	79	87
Contribution in Aid of Construction Advances	223	67
Obligations Under Operating Leases	13	14
Other Current Liabilities	72	93
TOTAL CURRENT LIABILITIES	1,628	1,418
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2026 and December 31, 2025 Amounts Include $65 and $78, Respectively, Related to Restoration Funding)	7,671	6,941
Deferred Income Taxes	1,522	1,430
Regulatory Liabilities and Deferred Investment Tax Credits	1,253	1,286
Obligations Under Operating Leases	38	40
Deferred Credits and Other Noncurrent Liabilities	187	134
TOTAL NONCURRENT LIABILITIES	10,671	9,831
TOTAL LIABILITIES	12,299	11,249
Rate Matters (Note 4)		
Commitments, Guarantees and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	2,547	2,546
Retained Earnings	3,516	3,283
Accumulated Other Comprehensive Income (Loss)	(3)	(3)
TOTAL COMMON SHAREHOLDER'S EQUITY	6,060	5,826
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 18,359	$ 17,075

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AEP TEXAS INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
OPERATING ACTIVITIES		
Net Income	$ 233	$ 223
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	225	216
Deferred Income Taxes	75	36
Allowance for Equity Funds Used During Construction	(39)	(24)
Pension Contributions to Qualified Plan Trust	—	(12)
Property Taxes	(61)	(58)
Change in Other Noncurrent Assets	(93)	(50)
Change in Other Noncurrent Liabilities	70	35
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(45)	(31)
Materials and Supplies	(57)	21
Accounts Payable	72	3
Accrued Taxes, Net	33	15
Other Current Assets	(16)	8
Other Current Liabilities	(37)	(23)
Net Cash Flows from Operating Activities	360	359
INVESTING ACTIVITIES		
Construction Expenditures	(1,449)	(863)
Contribution in Aid of Construction Advances	247	35
Other Investing Activities	(2)	(3)
Net Cash Flows Used for Investing Activities	(1,204)	(831)
FINANCING ACTIVITIES		
Capital Contribution from Parent	1	250
Issuance of Long-term Debt – Nonaffiliated	741	400
Change in Advances from Affiliates, Net	166	(175)
Retirement of Long-term Debt – Nonaffiliated	(62)	(12)
Other Financing Activities	(3)	(1)
Net Cash Flows from Financing Activities	843	462
Net Decrease in Cash, Cash Equivalents and Restricted Cash	(1)	(10)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	14	24
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 13	$ 14
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 149	$ 125
Construction Expenditures Included in Current Liabilities as of June 30,	357	207
Contributions in Aid of Construction Advances Included in Current Assets as of June 30,	23	—

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

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, 2026		As of June 30, 2025	
	(in millions)			
Plant In Service	$	17,671	$	16,090
Construction Work in Progress		2,636		2,105
Accumulated Depreciation and Amortization		2,075		1,760
Total Transmission Property, Net	$	18,232	$	16,435

AEP Transmission Company, LLC and Subsidiaries
Reconciliation of 2025 to 2026
Earnings Attributable to AEP Member
(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
2025 Earnings Attributable to AEP Member	$	556	$	767
Changes in Transmission Revenues:				
Transmission Revenues		(154)		(103)
Total Change in Transmission Revenues		(154)		(103)
Changes in Expenses and Other:				
Other Operation and Maintenance		(11)		(28)
Depreciation and Amortization		(9)		(23)
Taxes Other Than Income Taxes		(10)		(24)
Interest Income		—		2
Allowance for Equity Funds Used During Construction		5		5
Interest Expense		(7)		(17)
Total Change in Expenses and Other		(32)		(85)
Income Tax Expense		(208)		(207)
Net Income Attributable to Noncontrolling Interest		30		3
2026 Earnings Attributable to AEP Member	$	192	$	375

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Transmission Revenues** decreased $154 million primarily due to the following:
  - A $214 million decrease due to 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 continued transmission investment.

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

- **Other Operation and Maintenance** expenses increased $11 million primarily due to an increase in employee-related costs, vegetation management expenses, affiliated rent expense and other miscellaneous expenses.
- **Depreciation and Amortization** expenses increased $9 million primarily due to a higher depreciable base.
- **Taxes Other than Income Taxes** increased $10 million primarily due to higher property taxes driven by higher transmission investments.
- **Allowance for Equity Funds Used During Construction** increased $5 million primarily due to a higher CWIP base and higher equity rates.
- **Interest Expense** increased $7 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $208 million primarily due to the following:
  - A $254 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.

  This increase was partially offset by:
  - A $39 million decrease due to a decrease in pretax book income.
- **Net Income Attributable to Noncontrolling Interest** decreased $30 million primarily due to following:
  - A $54 million decrease due to higher 2025 earnings for Midwest Transmission Holdings due to the impact of the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $24 million increase due to the Midwest Transmission Holdings noncontrolling interest transaction that closed in June 2025.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Transmission Revenues** decreased $103 million primarily due to the following:
  - A $214 million decrease due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $111 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:

- **Operation and Maintenance** expenses increased $28 million primarily due to an increase in employee-related costs, vegetation management expenses, affiliated rent expense and other miscellaneous expenses.
- **Depreciation and Amortization** expenses increased $23 million due to a higher depreciable base.
- **Taxes Other than Income Taxes** increased $24 million primarily due to higher property taxes driven by increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $5 million primarily due to a higher CWIP base and higher equity rates.
- **Interest Expense** increased $17 million primarily due to higher long-term debt balances and interest rates.
- **Income Tax Expense** increased $207 million primarily due to the following:
  - A $254 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.

  This increase was partially offset by:
  - A $40 million decrease due to a decrease in pretax book income.
- **Net Income Attributable to Noncontrolling Interest** decreased $3 million primarily due to following:
  - A $54 million decrease due to higher 2025 earnings for Midwest Transmission Holdings due to the impact 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 the Midwest Transmission Holdings 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, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
REVENUES				
Transmission Revenues	$ 110	$ 111	$ 220	$ 217
Sales to AEP Affiliates	477	470	947	900
(Provision for)/Reversal of - Revenue Refund – Affiliated	(3)	127	(5)	120
(Provision for)/Reversal of - Revenue Refund – Nonaffiliated	(3)	34	(3)	32
Other Revenues	7	—	7	—
TOTAL REVENUES	588	742	1,166	1,269
EXPENSES				
Other Operation	45	36	86	65
Maintenance	8	6	18	11
Depreciation and Amortization	128	119	256	233
Taxes Other Than Income Taxes	86	76	174	150
TOTAL EXPENSES	267	237	534	459
OPERATING INCOME	321	505	632	810
Other Income (Expense):				
Interest Income – Affiliated	2	2	4	2
Allowance for Equity Funds Used During Construction	26	21	48	43
Interest Expense	(64)	(57)	(129)	(112)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	285	471	555	743
Income Tax Expense (Benefit)	62	(146)	122	(85)
NET INCOME	223	617	433	828
Net Income Attributable to Noncontrolling Interest	31	61	58	61
EARNINGS ATTRIBUTABLE TO AEP MEMBER	$ 192	$ 556	$ 375	$ 767

AEPTCo is wholly-owned by AEP Transmission Holdco.

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Paid-in Capital	Retained Earnings	Noncontrolling Interest	Total
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2024	$ 3,101	$ 3,850	$ —	$ 6,951
Capital Contribution from AEP Member	32			32
Dividends Paid to AEP Member		(42)		(42)
Net Income		211		211
TOTAL MEMBER'S EQUITY – MARCH 31, 2025	3,133	4,019	—	7,152
Capital Contribution from AEP Member	8			8
Dividends Paid to AEP Member		(2,836)		(2,836)
Midwest Transmission Holdings Noncontrolling Interest Transaction	1,791		992	2,783
Net Income		556	61	617
TOTAL MEMBER'S EQUITY – JUNE 30, 2025	$ 4,932	$ 1,739	$ 1,053	$ 7,724
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2025	$ 4,962	$ 1,651	$ 1,030	$ 7,643
Capital Contribution from AEP Member	233			233
Capital Contribution from Noncontrolling Interest			96	96
Dividends Paid to Noncontrolling Interest			(33)	(33)
Net Income		183	27	210
TOTAL MEMBER'S EQUITY – MARCH 31, 2026	5,195	1,834	1,120	8,149
Capital Contribution from AEP Member	16			16
Capital Contribution from Noncontrolling Interest			31	31
Dividends Paid to AEP Member		(141)		(141)
Dividends Paid to Noncontrolling Interest			(54)	(54)
Net Income		192	31	223
TOTAL MEMBER'S EQUITY – JUNE 30, 2026	$ 5,211	$ 1,885	$ 1,128	$ 8,224

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT ASSETS		
Advances to Affiliates	$ 222	$ 71
Accounts Receivable:		
Customers	66	94
Affiliated Companies	177	153
Total Accounts Receivable	243	247
Prepayments and Other Current Assets	31	4
TOTAL CURRENT ASSETS	496	322
TRANSMISSION PROPERTY		
Transmission Property	17,085	16,542
Other Property, Plant and Equipment	586	571
Construction Work in Progress	2,636	2,005
Total Transmission Property	20,307	19,118
Accumulated Depreciation and Amortization	2,075	1,915
TOTAL TRANSMISSION PROPERTY – NET	18,232	17,203
OTHER NONCURRENT ASSETS		
Regulatory Assets	84	73
Deferred Property Taxes	187	326
Deferred Charges and Other Noncurrent Assets	77	75
TOTAL OTHER NONCURRENT ASSETS	348	474
TOTAL ASSETS	$ 19,076	$ 17,999

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT LIABILITIES		
Advances from Affiliates	$ 58	$ 143
Accounts Payable:		
General	805	477
Affiliated Companies	113	164
Long-term Debt Due Within One Year – Nonaffiliated	425	425
Accrued Taxes	536	650
Accrued Interest	48	46
Contribution in Aid of Construction Advances	170	32
Obligations Under Operating Leases	1	1
Other Current Liabilities	15	9
TOTAL CURRENT LIABILITIES	2,171	1,947
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	6,331	6,174
Deferred Income Taxes	1,542	1,481
Regulatory Liabilities	779	708
Obligations Under Operating Leases	1	2
Deferred Credits and Other Noncurrent Liabilities	28	44
TOTAL NONCURRENT LIABILITIES	8,681	8,409
TOTAL LIABILITIES	10,852	10,356
Rate Matters (Note 4)		
Commitments, Guarantees and Contingencies (Note 5)		
MEMBER'S EQUITY		
Paid-in Capital	5,211	4,962
Retained Earnings	1,885	1,651
TOTAL MEMBER'S EQUITY	7,096	6,613
Noncontrolling Interest	1,128	1,030
TOTAL EQUITY	8,224	7,643
TOTAL LIABILITIES AND EQUITY	$ 19,076	$ 17,999

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Six Months Ended June 30, 2026	2025
OPERATING ACTIVITIES		
Net Income	$ 433	$ 828
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	256	233
Deferred Income Taxes	51	(137)
Allowance for Equity Funds Used During Construction	(48)	(43)
Property Taxes	139	131
Change in Other Noncurrent Assets	(23)	(46)
Change in Other Noncurrent Liabilities	(14)	(152)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	53	(45)
Accounts Payable	(46)	5
Accrued Taxes, Net	(132)	(202)
Other Current Assets	(9)	8
Other Current Liabilities	7	(15)
Net Cash Flows from Operating Activities	667	565
INVESTING ACTIVITIES		
Construction Expenditures	(865)	(787)
Change in Advances to Affiliates, Net	(151)	(38)
Contribution in Aid of Construction Advances	135	18
Other Investing Activities	(4)	5
Net Cash Flows Used for Investing Activities	(885)	(802)
FINANCING ACTIVITIES		
Capital Contribution from AEP Member	249	40
Capital Contribution from Noncontrolling Interest	127	—
Issuance of Long-term Debt – Nonaffiliated	768	419
Retirement of Long-term Debt – Nonaffiliated	(613)	(90)
Change in Advances from Affiliates, Net	(85)	(37)
Proceeds from the Midwest Transmission Holdings Noncontrolling Interest Transaction, Net of Transaction Costs	—	2,783
Dividends Paid to AEP Member	(141)	(2,878)
Dividends Paid to Noncontrolling Interest	(87)	—
Net Cash Flows from Financing Activities	218	237
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	$ 124	$ 107
Construction Expenditures Included in Current Liabilities as of June 30,	667	219

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

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,	
	2026	2025	2026	2025
	(in millions of KWhs)			
Retail:				
Residential	1,976	2,032	5,597	5,686
Commercial	1,443	1,465	2,941	2,965
Industrial	2,173	2,204	4,173	4,280
Miscellaneous	202	208	410	419
Total Retail	5,794	5,909	13,121	13,350
Wholesale (a)	534	576	985	1,303
Total KWhs	6,328	6,485	14,106	14,653

(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,	
	2026	2025	2026	2025
	(in degree days)			
Actual – Heating	48	69	1,382	1,433
Normal – Heating	79	80	1,360	1,359
Actual – Cooling	429	417	454	428
Normal – Cooling	394	387	400	393

Appalachian Power Company and Subsidiaries
Reconciliation of 2025 to 2026
Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Net Income	$ 107	$ 272
Changes in Revenues:		
Retail Revenues	(40)	(56)
Off-system Sales	2	2
Transmission Revenues	8	22
Other Revenues	(1)	(5)
Total Change in Revenues	(31)	(37)
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	14	57
Other Operation and Maintenance	(12)	(28)
Depreciation and Amortization	7	2
Taxes Other Than Income Taxes	(7)	(13)
Interest Income	(1)	(1)
Allowance for Equity Funds Used During Construction	(2)	(2)
Non-Service Cost Components of Net Periodic Benefit Cost	(2)	(3)
Interest Expense	(9)	(17)
Total Change in Expenses and Other	(12)	(5)
Income Tax Expense	(14)	15
2026 Net Income	$ 50	$ 245

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Retail Revenues** decreased $40 million primarily due to the following:
  - A $46 million decrease in fuel revenues.
  - A $14 million decrease in weather-normalized revenues primarily in the residential and commercial classes.
  - A $3 million decrease in weather-related usage due to a 30% decrease in heating degree days.

  These decreases were partially offset by:
  - A $32 million increase in base rate and rider revenues.
- **Transmission Revenues** increased $8 million primarily due to the following:
  - A $13 million increase due to continued transmission investment.

  This increase was partially offset by:
  - A $6 million decrease 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 following:
  - A $32 million increase in under-recovered deferred fuel regulatory assets primarily driven by lower authorized fuel rates in Virginia.

  This decrease was partially offset by:
  - A $14 million prior year impact to the West Virginia ENEC as a result of the June 2025 FERC NOLC order.

- **Other Operation and Maintenance** expenses increased $12 million primarily due to the following:
  - A $13 million increase in distribution expenses primarily due to storm-related expenses.
  - A $5 million increase in steam generation expenses primarily due to increased plant maintenance.
  - A $4 million increase in accretion expense related to AROs and the 2024 Legacy CCR Rule.
  - A $3 million increase in administrative and general expenses primarily due to employee-related costs.

  These increases were partially offset by:
  - A $15 million decrease in transmission expenses due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Depreciation and Amortization** expenses decreased $7 million primarily due to a decrease in depreciation expense at Amos and Mountaineer plants due to the issuance of Virginia securitization bonds.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to higher business and occupation taxes.
- **Interest Expense** increased $9 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $14 million primarily due to the following:
  - A $23 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.

  This increase was partially offset by:
  - A $9 million decrease due to a decrease in pretax book income.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Retail Revenues** decreased $56 million primarily due to the following:
  - A $101 million decrease in fuel revenues.
  - A $5 million decrease in weather-related usage primarily due to a 4% decrease in heating degree days.
  - A $3 million decrease in weather-normalized revenues primarily in the residential and commercial classes.

  These decreases were partially offset by:
  - A $57 million increase in base rate and rider revenues.
- **Transmission Revenues** increased $22 million primarily due to the following:
  - A $27 million increase due to continued transmission investment.

  This increase was partially offset by:
  - A $6 million decrease due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.
- **Other Revenues** decreased $5 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 $57 million primarily due to the following:
  - A $73 million increase in the under-recovered deferred fuel regulatory assets primarily driven by lower authorized fuel rates in Virginia.

  This decrease was partially offset by:
  - A $14 million prior year impact to the West Virginia ENEC as a result of the June 2025 FERC NOLC order.
- **Other Operation and Maintenance** expenses increased $28 million primarily due to the following:
  - A $27 million increase in distribution expenses primarily due to storm-related expenses.
  - A $9 million increase in steam generation expenses primarily due to increased plant maintenance.
  - A $7 million increase in administration and generation expenses primarily due to employee-related costs.
  - A $5 million increase in accretion expense related to AROs and the 2024 Legacy CCR Rule.

  These increases were partially offset by:
  - A $23 million gain from the sale of a non-utility investment in land.
- **Depreciation and Amortization** expenses decreased $2 million primarily due to the following:
  - A $24 million decrease due to an April 2026 order approving a final true-up to recover past MRBC costs that were not reflected in MRBC surcharge rates in a timely manner.

  This decrease was partially offset by:
  - A $23 million increase due to the cumulative regulatory deferral true-up for the impact of CAMT expense incurred related to IRS Notice 2026-07 allowing tax repair deductions in the calculation of CAMT.
- **Taxes Other Than Income Taxes** increased $13 million primarily due to the following:
  - An $8 million increase due to higher business and occupation taxes.
  - A $4 million increase in property taxes.

- **Interest Expense** increased $17 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $15 million primarily due to the following:
  - An $18 million decrease due to the cumulative true-up of CAMT related to IRS Notice 2026-07 allowing tax repair deductions in the calculation of CAMT.
  - A $14 million decrease due to an increase in PTCs.
  - A $9 million decrease due to a decrease in pretax book income.

  These decreases were partially offset by:
  - A $23 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.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
REVENUES				
Electric Generation, Transmission and Distribution	$ 833	$ 876	$ 1,904	$ 1,974
Sales to AEP Affiliates	81	66	173	138
Other Revenues	2	5	6	8
TOTAL REVENUES	916	947	2,083	2,120
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	277	291	641	698
Other Operation	203	211	420	433
Maintenance	104	84	203	162
Depreciation and Amortization	164	171	332	334
Taxes Other Than Income Taxes	45	38	92	79
TOTAL EXPENSES	793	795	1,688	1,706
OPERATING INCOME	123	152	395	414
Other Income (Expense):				
Interest Income	1	2	2	3
Allowance for Equity Funds Used During Construction	3	5	7	9
Non-Service Cost Components of Net Periodic Benefit Cost	4	6	8	11
Interest Expense	(80)	(71)	(155)	(138)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	51	94	257	299
Income Tax Expense (Benefit)	1	(13)	12	27
NET INCOME	$ 50	$ 107	$ 245	$ 272

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
Net Income	$ 50	$ 107	$ 245	$ 272
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2026 and 2025, Respectively, and $0 and $0 for the Six Months Ended June 30, 2026 and 2025, Respectively	(1)	(1)	(1)	(1)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2026 and 2025, Respectively, and $0 and $0 for the Six Months Ended June 30, 2026 and 2025, Respectively	—	—	—	—
TOTAL OTHER COMPREHENSIVE LOSS	(1)	(1)	(1)	(1)
TOTAL COMPREHENSIVE INCOME	$ 49	$ 106	$ 244	$ 271

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2024	$ 260	$ 1,945	$ 3,532	$ 11	$ 5,748
Common Stock Dividends			(50)		(50)
Net Income			165		165
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2025	260	1,945	3,647	11	5,863
Capital Contribution from Parent		7			7
Net Income			107		107
Other Comprehensive Loss				(1)	(1)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2025	$ 260	$ 1,952	$ 3,754	$ 10	$ 5,976
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2025	$ 260	$ 1,957	$ 3,939	$ 24	$ 6,180
Capital Contribution from Parent		81			81
Net Income			195		195
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2026	260	2,038	4,134	24	6,456
Common Stock Dividends			(700)		(700)
Net Income			50		50
Other Comprehensive Loss				(1)	(1)
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2026	$ 260	$ 2,038	$ 3,484	$ 23	$ 5,805

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4	$ 5
Restricted Cash for Securitized Funding (June 30, 2026 and December 31, 2025 Amounts Include $25 and $18, Respectively, Related to Appalachian Consumer Rate Relief Funding and Appalachian Recovery Funding)	25	18
Advances to Affiliates	17	17
Accounts Receivable:		
Customers	223	171
Affiliated Companies	165	142
Accrued Unbilled Revenues	61	112
Allowance for Credit Losses	(2)	(2)
Total Accounts Receivable	447	423
Fuel	245	229
Materials and Supplies	157	139
Risk Management Assets	171	81
Regulatory Asset for Under-Recovered Fuel Costs	163	83
Prepayments and Other Current Assets	58	38
TOTAL CURRENT ASSETS	1,287	1,033
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	5,688	7,886
Transmission	5,339	5,277
Distribution	6,074	5,938
Other Property, Plant and Equipment	1,218	1,175
Construction Work in Progress	878	802
Total Property, Plant and Equipment	19,197	21,078
Accumulated Depreciation and Amortization	5,135	6,365
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	14,062	14,713
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,407	1,439
Securitized Assets (June 30, 2026 and December 31, 2025 Amounts Include $1,424 and $78, Respectively, Related to Appalachian Consumer Rate Relief Funding and Appalachian Recovery Funding)	1,424	78
Employee Benefits and Pension Assets	257	251
Operating Lease Assets	97	95
Deferred Charges and Other Noncurrent Assets	175	183
TOTAL OTHER NONCURRENT ASSETS	3,360	2,046
TOTAL ASSETS	$ 18,709	$ 17,792

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2026 and December 31, 2025
(Unaudited)

	June 30, 2026	December 31, 2025
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 126	$ 209
Accounts Payable:		
General	492	375
Affiliated Companies	122	173
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2026 and December 31, 2025 Amounts Include $65 and $30, Respectively, Related to Appalachian Consumer Rate Relief Funding and Appalachian Recovery Funding)	1,315	1,131
Customer Deposits	99	94
Accrued Taxes	121	116
Obligations Under Operating Leases	14	15
Other Current Liabilities	297	271
TOTAL CURRENT LIABILITIES	2,586	2,384
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2026 and December 31, 2025 Amounts Include $1,376 and $62, Respectively, Related to Appalachian Consumer Rate Relief Funding and Appalachian Recovery Funding)	6,120	5,128
Deferred Income Taxes	2,236	2,130
Regulatory Liabilities and Deferred Investment Tax Credits	1,064	1,111
Asset Retirement Obligations	741	707
Employee Benefits and Pension Obligations	26	26
Obligations Under Operating Leases	84	81
Deferred Credits and Other Noncurrent Liabilities	47	45
TOTAL NONCURRENT LIABILITIES	10,318	9,228
TOTAL LIABILITIES	12,904	11,612
Rate Matters (Note 4)		
Commitments, Guarantees and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260	260
Paid-in Capital	2,038	1,957
Retained Earnings	3,484	3,939
Accumulated Other Comprehensive Income (Loss)	23	24
TOTAL COMMON SHAREHOLDER'S EQUITY	5,805	6,180
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 18,709	$ 17,792

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
OPERATING ACTIVITIES		
Net Income	$ 245	$ 272
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	332	334
Deferred Income Taxes	60	(5)
Allowance for Equity Funds Used During Construction	(7)	(9)
Mark-to-Market of Risk Management Contracts	(80)	(73)
Deferred Fuel Over/Under-Recovery, Net	(72)	6
Change in Regulatory Assets	(96)	(117)
Change in Other Noncurrent Assets	(40)	29
Change in Other Noncurrent Liabilities	(19)	6
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(20)	6
Fuel, Materials and Supplies	(34)	38
Accounts Payable	73	(61)
Accrued Taxes, Net	1	(39)
Other Current Assets	(11)	18
Other Current Liabilities	17	(19)
Net Cash Flows from Operating Activities	349	386
INVESTING ACTIVITIES		
Construction Expenditures	(497)	(528)
Acquisitions of Assets	(352)	—
Other Investing Activities	36	4
Net Cash Flows Used for Investing Activities	(813)	(524)
FINANCING ACTIVITIES		
Capital Contribution from Parent	81	7
Issuance of Long-term Debt – Nonaffiliated	1,364	528
Change in Advances from Affiliates, Net	(83)	78
Retirement of Long-term Debt – Nonaffiliated	(191)	(418)
Principal Payments for Finance Lease Obligations	(2)	(4)
Dividends Paid on Common Stock	(700)	(50)
Other Financing Activities	1	1
Net Cash Flows from Financing Activities	470	142
Net Increase in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	6	4
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	23	20
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 29	$ 24
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 150	$ 134
Noncash Acquisitions Under Finance Leases	3	2
Construction Expenditures Included in Current Liabilities as of June 30,	126	115

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
	(in millions of KWhs)			
Retail:				
Residential	1,102	1,097	2,610	2,650
Commercial	2,341	1,414	4,522	2,686
Industrial	1,812	1,856	3,539	3,604
Miscellaneous	10	9	22	22
Total Retail	5,265	4,376	10,693	8,962
Wholesale (a)	1,884	1,507	3,551	3,943
Total KWhs	7,149	5,883	14,244	12,905

(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,	
	2026	2025	2026	2025
	(in degree days)			
Actual – Heating	174	217	2,233	2,335
Normal – Heating	236	237	2,357	2,365
Actual – Cooling	222	280	223	280
Normal – Cooling	284	284	285	285

Indiana Michigan Power Company and Subsidiaries
Reconciliation of 2025 to 2026
Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Net Income	$ 124	$ 182
Changes in Revenues:		
Retail Revenues	121	249
Off-system Sales	(38)	44
Transmission Revenues	(16)	(13)
Other Revenues	(4)	(7)
Total Change in Revenues	63	273
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(20)	(76)
Purchased Electricity from AEP Affiliates	8	7
Other Operation and Maintenance	(17)	(50)
Depreciation and Amortization	(9)	(16)
Taxes Other Than Income Taxes	(4)	(2)
Other Income	4	7
Non-Service Cost Components of Net Periodic Benefit Cost	(2)	(3)
Interest Expense	(10)	(18)
Total Change in Expenses and Other	(50)	(151)
Income Tax Expense	(40)	(59)
2026 Net Income	$ 97	$ 245

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Retail Revenues** increased $121 million primarily due to the following:
  - A $79 million increase in weather-normalized revenues primarily in the commercial class.
  - A $47 million increase in fuel revenues.
  - An $8 million increase in rider revenues.
  - A $6 million increase due to a decrease in regulatory provisions for refund.

  These increases were partially offset by:
  - An $8 million decrease in weather-related usage primarily due to a 21% decrease in cooling degree days.
- **Off-system Sales** decreased $38 million primarily due to Rockport Plant, Unit 2 merchant sales and economic hedging activity.
- **Transmission Revenues** decreased $16 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 Expense changed between years as follows:

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $20 million primarily due to an increase in recoverable fuel and purchased power costs, partially offset by a decrease in Rockport Plant, Unit 2, merchant generation fuel costs.
- **Purchased Electricity from AEP Affiliates** expenses decreased $8 million primarily due to a decrease in purchased electricity from AEGCo.
- **Other Operation and Maintenance** expenses increased $17 million primarily due to a $14 million increase in transmission expenses primarily due to an $8 million increase in recoverable PJM expenses and a $6 million increase due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

- **Depreciation and Amortization** increased $9 million primarily due to a higher depreciable base.
- **Interest Expense** increased $10 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $40 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 stand-alone NOLCs in transmission formula rates.
  - A $3 million increase due to an increase in pretax book income.
  - A $3 million increase due to an increase in state taxes.
  - A $3 million increase due to a decrease in PTCs.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Retail Revenues** increased $249 million primarily due to the following:
  - A $134 million increase in weather-normalized margins primarily in the commercial class.
  - A $65 million increase in fuel revenues.
  - A $55 million increase in rider revenues.
  - A $15 million increase due to a decrease in regulatory provisions for refund.

  These increases were partially offset by:
  - A $10 million decrease in weather-related usage primarily due to a 20% decrease in cooling degree days.
- **Off-system Sales** increased $44 million primarily due to Rockport Plant, Unit 2 merchant sales during Winter Storm Fern in January 2026, partially offset by a decrease in merchant sales and economic hedging activity.
- **Transmission Revenues** decreased $13 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 Expense changed between years as follows:

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $76 million primarily due to an increase in recoverable fuel and purchased power costs, partially offset by a decrease in Rockport Plant, Unit 2, merchant generation fuel costs.
- **Purchased Electricity from AEP Affiliates** decreased $7 million primarily due to a decrease in purchased electricity from AEGCo.
- **Other Operation and Maintenance** expenses increased $50 million primarily due to the following:
  - A $26 million increase in transmission expenses primarily due to a $17 million increase in recoverable PJM expenses and a $6 million increase due to the June 2025 FERC order related to the treatment of stand-alone NOLCs in transmission formula rates.
  - A $7 million increase in distribution expenses primarily due to an increase in vegetation management costs and other distribution-related expenses.
  - A $7 million increase in administrative and general expenses.
  - A $6 million increase in demand side management expenses.
  - A $5 million increase in steam generation expenses primarily due to the acquisition of the Oregon Clean Energy Center in March 2026.

  These increases were partially offset by:
  - A $7 million decrease due to an increased Nuclear Electric Insurance Limited distribution.
  - A $5 million decrease in non-utility operation expenses due to a decrease in RTD barging expenses.
- **Depreciation and Amortization** expenses increased $16 million primarily due to the following:
  - An $11 million increase due to a higher depreciable base.
  - An $8 million increase due to NOLC-related Excess ADIT deferrals recorded in 2025 and the amortization of these deferrals recorded in 2026 for IURC approved recovery through I&M’s Indiana tax rider.

  These increases were partially offset by:
  - A $6 million decrease due to Michigan PTC deferral activity.
- **Other Income** increased $7 million primarily due to an increase in AFUDC due to a higher AFUDC base and an increase in equity return rates.
- **Interest Expense** increased $18 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $59 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 stand-alone NOLCs in transmission formula rates.
  - A $26 million increase due to an increase in pretax book income.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
REVENUES				
Electric Generation, Transmission and Distribution	$ 811	$ 736	$ 1,772	$ 1,495
Sales to AEP Affiliates	2	2	7	6
(Provision for)/Reversal of - Revenue Refund – Affiliated	(4)	9	(4)	8
Provision for Refund – Nonaffiliated	(23)	(26)	(71)	(84)
Other Revenues – Affiliated	13	14	27	30
Other Revenues – Nonaffiliated	1	2	2	5
TOTAL REVENUES	800	737	1,733	1,460
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	152	132	384	308
Purchased Electricity from AEP Affiliates	58	66	135	142
Other Operation	202	177	390	348
Maintenance	80	88	156	148
Depreciation and Amortization	138	129	269	253
Taxes Other Than Income Taxes	26	22	50	48
TOTAL EXPENSES	656	614	1,384	1,247
OPERATING INCOME	144	123	349	213
Other Income (Expense):				
Other Income	8	4	16	9
Non-Service Cost Components of Net Periodic Benefit Cost	3	5	7	10
Interest Expense	(49)	(39)	(92)	(74)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	106	93	280	158
Income Tax Expense (Benefit)	9	(31)	35	(24)
NET INCOME	$ 97	$ 124	$ 245	$ 182

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
Net Income	$ 97	$ 124	$ 245	$ 182
OTHER COMPREHENSIVE INCOME, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2026 and 2025, Respectively, and $0 and $0 for the Six Months Ended June 30, 2026 and 2025, Respectively	—	—	—	—
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2026 and 2025, Respectively, and $0 and $0 for the Six Months Ended June 30, 2026 and 2025, Respectively	—	—	—	—
TOTAL OTHER COMPREHENSIVE INCOME	—	—	—	—
TOTAL COMPREHENSIVE INCOME	$ 97	$ 124	$ 245	$ 182

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2024	$ 57	$ 1,012	$ 2,328	$ —	$ 3,397
Common Stock Dividends			(50)		(50)
Net Income			58		58
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2025	57	1,012	2,336	—	3,405
Capital Contribution from Parent		7			7
Net Income			124		124
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2025	$ 57	$ 1,019	$ 2,460	$ —	$ 3,536
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2025	$ 57	$ 1,033	$ 2,692	$ 2	$ 3,784
Net Income			148		148
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2026	57	1,033	2,840	2	3,932
Capital Contribution from Parent		25			25
Common Stock Dividends			(50)		(50)
Net Income			97		97
TOTAL COMMON SHAREHOLDER'S EQUITY - JUNE 30, 2026	$ 57	$ 1,058	$ 2,887	$ 2	$ 4,004

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2	$ 2
Advances to Affiliates	63	192
Accounts Receivable:		
Customers	110	103
Affiliated Companies	87	90
Accrued Unbilled Revenues	—	17
Miscellaneous	14	2
Total Accounts Receivable	211	212
Fuel	65	61
Materials and Supplies	241	222
Risk Management Assets	22	10
Accrued Tax Benefits	31	32
Prepayments and Other Current Assets	82	53
TOTAL CURRENT ASSETS	717	784
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,212	5,483
Transmission	2,155	2,055
Distribution	3,950	3,823
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	1,389	1,058
Construction Work in Progress	541	403
Total Property, Plant and Equipment	14,247	12,822
Accumulated Depreciation, Depletion and Amortization	5,207	4,878
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,040	7,944
OTHER NONCURRENT ASSETS		
Regulatory Assets	553	585
Spent Nuclear Fuel and Decommissioning Trusts	5,241	4,916
Operating Lease Assets	46	52
Deferred Charges and Other Noncurrent Assets	344	344
TOTAL OTHER NONCURRENT ASSETS	6,184	5,897
TOTAL ASSETS	$ 15,941	$ 14,625

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2026 and December 31, 2025
(dollars in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 304	$ 232
Affiliated Companies	110	125
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2026 and December 31, 2025 Amounts Include $91 and $117, Respectively, Related to DCC Fuel)	91	117
Customer Deposits	56	55
Accrued Taxes	98	112
Accrued Interest	55	42
Obligations Under Operating Leases	15	17
Regulatory Liability for Over-Recovered Fuel Costs	97	19
Other Current Liabilities	217	230
TOTAL CURRENT LIABILITIES	1,043	949
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,055	3,444
Deferred Income Taxes	1,216	1,219
Regulatory Liabilities and Deferred Investment Tax Credits	3,317	2,938
Asset Retirement Obligations	2,208	2,165
Obligations Under Operating Leases	32	37
Deferred Credits and Other Noncurrent Liabilities	66	89
TOTAL NONCURRENT LIABILITIES	10,894	9,892
TOTAL LIABILITIES	11,937	10,841
Rate Matters (Note 4)		
Commitments, Guarantees and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	57	57
Paid-in Capital	1,058	1,033
Retained Earnings	2,887	2,692
Accumulated Other Comprehensive Income (Loss)	2	2
TOTAL COMMON SHAREHOLDER'S EQUITY	4,004	3,784
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 15,941	$ 14,625

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
OPERATING ACTIVITIES		
Net Income	$ 245	$ 182
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	269	253
Deferred Income Taxes	(10)	(46)
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	37	(23)
Allowance for Equity Funds Used During Construction	(12)	(8)
Mark-to-Market of Risk Management Contracts	(12)	7
Amortization of Nuclear Fuel	64	52
Deferred Fuel Over/Under-Recovery, Net	78	9
Change in Other Noncurrent Assets	(26)	(14)
Change in Other Noncurrent Liabilities	94	55
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	10	(10)
Fuel, Materials and Supplies	(18)	26
Accounts Payable	22	28
Accrued Taxes, Net	(13)	(1)
Other Current Assets	11	3
Other Current Liabilities	(5)	(14)
Net Cash Flows from Operating Activities	734	499
INVESTING ACTIVITIES		
Construction Expenditures	(367)	(306)
Change in Advances to Affiliates, Net	129	—
Purchases of Investment Securities	(1,249)	(1,330)
Sales of Investment Securities	1,209	1,294
Acquisitions of Generation Facilities	(965)	—
Acquisitions of Nuclear Fuel	(51)	(45)
Other Investing Activities	9	27
Net Cash Flows Used for Investing Activities	(1,285)	(360)
FINANCING ACTIVITIES		
Capital Contribution from Parent	25	7
Issuance of Long-term Debt – Nonaffiliated	640	249
Change in Advances from Affiliates, Net	—	(101)
Retirement of Long-term Debt – Nonaffiliated	(63)	(240)
Principal Payments for Finance Lease Obligations	(2)	(3)
Dividends Paid on Common Stock	(50)	(50)
Other Financing Activities	1	1
Net Cash Flows from (Used for) Financing Activities	551	(137)
Net Increase in Cash and Cash Equivalents	—	2
Cash and Cash Equivalents at Beginning of Period	2	2
Cash and Cash Equivalents at End of Period	$ 2	$ 4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 70	$ 72
Noncash Acquisitions Under Finance Leases	1	1
Construction Expenditures Included in Current Liabilities as of June 30,	99	82
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	33	33

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

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,	
	2026	2025	2026	2025
	(in millions of KWhs)			
Retail:				
Residential	2,952	3,024	6,953	7,119
Commercial	8,251	6,323	15,970	11,812
Industrial	3,727	3,748	7,105	7,134
Miscellaneous	23	25	51	53
Total Retail (a)	14,953	13,120	30,079	26,118
Wholesale (b)	256	464	899	1,131
Total KWhs	15,209	13,584	30,978	27,249

(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,	
	2026	2025	2026	2025
	(in degree days)			
Actual – Heating	132	170	1,996	2,077
Normal – Heating	172	173	1,991	1,993
Actual – Cooling	309	336	321	342
Normal – Cooling	325	323	328	325

Ohio Power Company and Subsidiaries
Reconciliation of 2025 to 2026
Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Net Income	$ 103	$ 166
Changes in Revenues:		
Retail Revenues	90	142
Off-system Sales	(7)	18
Transmission Revenues	13	20
Other Revenues	(3)	(6)
Total Change in Revenues	93	174
Changes in Expenses and Other:		
Purchased Electricity for Resale	17	13
Purchased Electricity from AEP Affiliates	(1)	(5)
Other Operation and Maintenance	(90)	(98)
Depreciation and Amortization	4	(13)
Taxes Other Than Income Taxes	(28)	(25)
Other Income	—	(1)
Allowance for Equity Funds Used During Construction	(1)	(1)
Non-Service Cost Components of Net Periodic Benefit Cost	(2)	3
Interest Expense	3	1
Total Change in Expenses and Other	(98)	(126)
Income Tax Expense	11	13
Equity Earnings of Unconsolidated Subsidiaries	—	(1)
2026 Net Income	$ 109	$ 226

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Retail Revenues** increased $90 million primarily due to the following:
  - A $79 million increase in rider revenues.
  - A $9 million increase due to higher prices for purchased power to serve OPCo's SSO customers.
- **Off-system Sales** decreased $7 million primarily due to decreased sales of OVEC purchased power driven by lower market prices.
- **Transmission Revenues** increased $13 million primarily due to continued transmission investment.

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

- **Purchased Electricity for Resale** expenses decreased $17 million primarily due to the following:
  - A $23 million decrease in OVEC purchased power costs.

  This decrease was partially offset by:
  - A $7 million increase in recoverable auction purchases to serve SSO customers.
- **Other Operation and Maintenance** expenses increased $90 million primarily due to the following:
  - A $75 million increase primarily due to recoverable PJM transmission expenses.
  - A $6 million increase primarily due to recoverable distribution vegetation management expenses.

- **Taxes Other Than Income Taxes** increased $28 million primarily due to the following:
  - A $23 million increase in property taxes.
  - A $5 million increase in state excise taxes due to increased billed KWhs.
- **Income Tax Expense** decreased $11 million primarily due to Excess ADIT credits refunded to customers as approved in the 2025 base rate case.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Retail Revenues** increased $142 million primarily due to the following:
  - A $75 million increase in rider revenues.
  - A $60 million increase due to higher prices for purchased power to serve OPCo's SSO customers.
  - A $10 million increase in weather-normalized revenues primarily in the residential class.

  These increases were partially offset by:
  - A $20 million decrease in weather-related usage driven by a 6% decrease in cooling degree days.
- **Off-system Sales** increased $18 million primarily due to increased sales of OVEC purchased power driven by higher market prices and volume.
- **Transmission Revenues** increased $20 million primarily due to continued transmission investment.
- **Other Revenues** decreased $6 million primarily due to lower third-party Legacy Generation Resource Rider revenues 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 $13 million primarily due to the following:
  - A $44 million decrease as a result of legislation approved in Ohio in 2025 related to the elimination of OPCo's ability to recover from customers, or refund to, the difference between purchased power expenses from OVEC.
  - A $30 million decrease in OVEC purchased power costs.

  These decreases were partially offset by:
  - A $58 million increase in recoverable auction purchases to serve SSO customers.
- **Purchased Electricity from AEP Affiliates** expenses increased $5 million primarily due to an increase in recoverable purchases to serve SSO customers.
- **Other Operation and Maintenance** expenses increased $98 million primarily due to the following:
  - A $65 million increase primarily due to a $50 million increase in recoverable PJM transmission expenses and an $11 million increase in recoverable transmission storm restoration costs and vegetation management expenses.
  - A $15 million increase related to recoverable energy assistance program expenses for qualified Ohio customers.
  - A $14 million increase primarily due to recoverable distribution vegetation management expenses.
- **Depreciation and Amortization** expenses increased $13 million primarily due to the deferral of income tax benefit from Excess ADIT credits to be refunded to customers as approved in the 2025 base rate case.
- **Taxes Other Than Income Taxes** increased $25 million primarily due to the following:
  - An $18 million increase in property taxes.
  - A $7 million increase in state excise taxes due to increased billed KWhs.
- **Income Tax Expense** decreased $13 million primarily due to the following:
  - A $22 million decrease due to an increase in Excess ADIT credits refunded to customers as approved in the 2025 base rate case.

  This decrease was partially offset by:
  - A $10 million increase 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, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30, 2026	Three Months Ended June 30, 2025	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
REVENUES				
Electricity, Transmission and Distribution	$ 994	$ 910	$ 2,063	$ 1,900
Sales to AEP Affiliates	14	6	27	16
Other Revenues	4	3	7	7
TOTAL REVENUES	1,012	919	2,097	1,923
EXPENSES				
Purchased Electricity for Resale	172	189	423	436
Purchased Electricity from AEP Affiliates	16	15	36	31
Other Operation	360	283	683	617
Maintenance	76	63	147	115
Depreciation and Amortization	91	95	202	189
Taxes Other Than Income Taxes	148	120	304	279
TOTAL EXPENSES	863	765	1,795	1,667
OPERATING INCOME	149	154	302	256
Other Income (Expense):				
Other Income	—	—	—	1
Allowance for Equity Funds Used During Construction	6	7	13	14
Non-Service Cost Components of Net Periodic Benefit Cost	3	5	12	9
Interest Expense	(37)	(40)	(77)	(78)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	121	126	250	202
Income Tax Expense	12	23	24	37
Equity Earnings of Unconsolidated Subsidiaries	—	—	—	1
NET INCOME	$ 109	$ 103	$ 226	$ 166

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	$ 321	$ 1,020	$ 2,543	$ 3,884
Common Stock Dividends			(46)	(46)
Net Income			63	63
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2025	321	1,020	2,560	3,901
Capital Contribution from Parent		2		2
Common Stock Dividends			(25)	(25)
Net Income			103	103
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2025	$ 321	$ 1,022	$ 2,638	$ 3,981
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2025	$ 321	$ 1,030	$ 2,800	$ 4,151
Capital Contribution from Parent		39		39
Net Income			117	117
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2026	321	1,069	2,917	4,307
Capital Contribution from Parent		65		65
Net Income			109	109
Noncash Distribution to Parent			(2)	(2)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2026	$ 321	$ 1,134	$ 3,024	$ 4,479

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT ASSETS		
Cash and Cash Equivalents	$ 5	$ 5
Accounts Receivable:		
Customers	153	109
Affiliated Companies	134	132
Accrued Unbilled Revenues	7	29
Total Accounts Receivable	294	270
Materials and Supplies	203	191
Prepayments and Other Current Assets	15	25
TOTAL CURRENT ASSETS	517	491
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	4,009	3,916
Distribution	8,057	7,661
Other Property, Plant and Equipment	1,307	1,289
Construction Work in Progress	808	811
Total Property, Plant and Equipment	14,181	13,677
Accumulated Depreciation and Amortization	3,048	2,993
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	11,133	10,684
OTHER NONCURRENT ASSETS		
Regulatory Assets	389	326
Operating Lease Assets	46	50
Deferred Charges and Other Noncurrent Assets	446	659
TOTAL OTHER NONCURRENT ASSETS	881	1,035
TOTAL ASSETS	$ 12,531	$ 12,210

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2026 and December 31, 2025
(dollars in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT LIABILITIES		
Advances from Affiliates	$ 64	$ 79
Accounts Payable:		
General	426	391
Affiliated Companies	194	197
Risk Management Liabilities	4	5
Customer Deposits	107	108
Accrued Taxes	663	858
Obligations Under Operating Leases	13	13
Other Current Liabilities	222	239
TOTAL CURRENT LIABILITIES	1,693	1,890
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,720	3,718
Long-term Risk Management Liabilities	24	28
Deferred Income Taxes	1,359	1,268
Regulatory Liabilities and Deferred Investment Tax Credits	878	893
Obligations Under Operating Leases	33	37
Deferred Credits and Other Noncurrent Liabilities	345	225
TOTAL NONCURRENT LIABILITIES	6,359	6,169
TOTAL LIABILITIES	8,052	8,059
Rate Matters (Note 4)		
Commitments, Guarantees and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock –No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321	321
Paid-in Capital	1,134	1,030
Retained Earnings	3,024	2,800
TOTAL COMMON SHAREHOLDER'S EQUITY	4,479	4,151
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,531	$ 12,210

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

OHIO POWER COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
OPERATING ACTIVITIES		
Net Income	$ 226	$ 166
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	202	189
Deferred Income Taxes	55	14
Allowance for Equity Funds Used During Construction	(13)	(14)
Mark-to-Market of Risk Management Contracts	(5)	—
Property Taxes	213	206
Security Deposits	114	49
Change in Regulatory Assets	(50)	13
Change in Other Noncurrent Assets	(40)	28
Change in Other Noncurrent Liabilities	10	(58)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(9)	2
Materials and Supplies	(12)	(19)
Accounts Payable	30	(5)
Customer Deposits	(1)	(15)
Accrued Taxes, Net	(186)	(306)
Other Current Assets	3	7
Other Current Liabilities	(32)	(23)
Net Cash Flows from Operating Activities	505	234
INVESTING ACTIVITIES		
Construction Expenditures	(617)	(505)
Change in Advances to Affiliates, Net	—	115
Other Investing Activities	25	27
Net Cash Flows Used for Investing Activities	(592)	(363)
FINANCING ACTIVITIES		
Capital Contribution from Parent	104	2
Change in Advances from Affiliates, Net	(15)	203
Principal Payments for Finance Lease Obligations	(2)	(2)
Dividends Paid on Common Stock	—	(71)
Other Financing Activities	—	1
Net Cash Flows from Financing Activities	87	133
Net Increase in Cash and Cash Equivalents	—	4
Cash and Cash Equivalents at Beginning of Period	5	4
Cash and Cash Equivalents at End of Period	$ 5	$ 8
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 72	$ 72
Noncash Acquisitions Under Finance Leases	1	1
Construction Expenditures Included in Current Liabilities as of June 30,	140	121

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

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,	
	2026	2025	2026	2025
	(in millions of KWhs)			
Retail:				
Residential	1,406	1,319	2,770	2,911
Commercial	1,513	1,485	2,860	2,806
Industrial	1,502	1,483	2,913	2,860
Miscellaneous	329	325	613	604
Total Retail	4,750	4,612	9,156	9,181
Wholesale (a)	17	28	54	85
Total KWhs	4,767	4,640	9,210	9,266

(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,	
	2026	2025	2026	2025
	(in degree days)			
Actual – Heating	1	31	761	1,193
Normal – Heating	43	43	1,092	1,081
Actual – Cooling	756	605	850	629
Normal – Cooling	705	709	726	729

Public Service Company of Oklahoma
Reconciliation of 2025 to 2026
Net Income
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Net Income	$ 63	$ 91
Changes in Revenues:		
Retail Revenues (a)	59	103
Transmission Revenues	(4)	(4)
Other Revenues	(3)	(2)
Total Change in Revenues	52	97
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(8)	(43)
Other Operation and Maintenance	(26)	(63)
Depreciation and Amortization	(7)	(11)
Taxes Other Than Income Taxes	(2)	(7)
Interest Income	—	(2)
Allowance for Equity Funds Used During Construction	(1)	(1)
Non-Service Cost Components of Net Periodic Benefit Cost (Credit)	(5)	(5)
Interest Expense	(14)	(27)
Total Change in Expenses and Other	(63)	(159)
Income Tax Benefit	2	40
2026 Net Income	$ 54	$ 69

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

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Retail Revenues** increased $59 million primarily due to the following:
  - A $64 million increase in rider revenues.
  - A $12 million increase in weather-related usage primarily due to a 25% increase in cooling degree days.

  These increases were partially offset by:
  - A $9 million decrease in weather-normalized revenues primarily in the residential class.

Expenses and Other changed between years as follows:

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $8 million primarily due to a $17 million increase in recoverable PTCs partially offset by a $10 million decrease related to the impact on deferred fuel costs from decreased fuel revenues.
- **Other Operation and Maintenance** expenses increased $26 million primarily due to the following:
  - A $15 million increase in generation expenses primarily due to acquisitions of generation facilities.
  - A $9 million increase in employee-related costs.
  - A $6 million increase in distribution expenses primarily due to overhead line maintenance.

  These increases were partially offset by:
  - A $5 million decrease in transmission expenses primarily due to a $19 million decrease related to the June 2025 FERC NOLC order partially offset by a $13 million increase in SPP expenses.
- **Depreciation and Amortization** expenses increased $7 million primarily due to a higher depreciable base.
- **Interest Expense** increased $14 million primarily due to higher long-term debt balances.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Retail Revenues** increased $103 million primarily due to the following:
  - A $126 million increase in rider revenues.
  - A $6 million increase in weather-related usage primarily due to a 35% increase in cooling degree days.

  These increases were partially offset by:
  - A $17 million decrease in weather-normalized revenues primarily in the residential class.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses increased $43 million primarily due to a $53 million increase in recoverable PTCs partially offset by a $10 million decrease primarily in purchased power prices.
- **Other Operation and Maintenance** expenses increased $63 million primarily due to the following:
  - A $25 million increase in generation expenses primarily due to acquisitions of generation facilities.
  - A $15 million increase in transmission expenses primarily due to a $30 million increase in SPP expenses partially offset by a $19 million decrease related to the June 2025 FERC NOLC order.
  - An $11 million increase in distribution expenses primarily due to overhead line maintenance.
  - An $11 million increase in employee-related costs.
- **Depreciation and Amortization** expenses increased $11 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to property taxes on acquired generation facilities.
- **Interest Expense** increased $27 million primarily due to the following:
  - A $20 million increase due to higher long-term debt balances.
  - A $3 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.
- **Income Tax Benefit** increased $40 million primarily due to the following:
  - A $38 million increase due to an increase in PTCs.
  - A $13 million increase due to a decrease in pretax book income.

  These increases were partially offset by:
  - A $13 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.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
REVENUES				
Electric Generation, Transmission and Distribution	$ 517	$ 466	$ 951	$ 856
Sales to AEP Affiliates	4	1	8	2
Other Revenues	—	2	1	5
TOTAL REVENUES	521	469	960	863
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	180	172	344	301
Other Operation	138	123	265	224
Maintenance	41	30	80	58
Depreciation and Amortization	74	67	147	136
Taxes Other Than Income Taxes	22	20	45	38
TOTAL EXPENSES	455	412	881	757
OPERATING INCOME	66	57	79	106
Other Income (Expense):				
Interest Income	—	—	—	2
Allowance for Equity Funds Used During Construction	2	3	5	6
Non-Service Cost Components of Net Periodic Benefit Cost (Credit)	(3)	2	(1)	4
Interest Expense	(43)	(29)	(86)	(59)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (BENEFIT)	22	33	(3)	59
Income Tax Expense (Benefit)	(32)	(30)	(72)	(32)
NET INCOME	$ 54	$ 63	$ 69	$ 91

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
Net Income	$ 54	$ 63	$ 69	$ 91
OTHER COMPREHENSIVE LOSS, NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2026 and 2025, Respectively, and $0 and $0 for the Six Months Ended June 30, 2026 and 2025, Respectively.	—	—	—	(1)
TOTAL COMPREHENSIVE INCOME	$ 54	$ 63	$ 69	$ 90

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	$ 157	$ 1,042	$ 1,484	$ 3	$ 2,686
Net Income			28		28
Other Comprehensive Loss				(1)	(1)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2025	157	1,042	1,512	2	2,713
Capital Contribution from Parent		300			300
Net Income			63		63
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2025	$ 157	$ 1,342	$ 1,575	$ 2	$ 3,076
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2025	$ 157	$ 1,718	$ 1,736	$ 2	$ 3,613
Net Income			15		15
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2026	157	1,718	1,751	2	3,628
Capital Contribution from Parent		113			113
Net Income			54		54
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2026	$ 157	$ 1,831	$ 1,805	$ 2	$ 3,795

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3	$ 2
Accounts Receivable:		
Customers	103	109
Affiliated Companies	125	45
Miscellaneous	13	4
Total Accounts Receivable	241	158
Fuel	3	3
Materials and Supplies	140	119
Risk Management Assets	43	42
Accrued Tax Benefits	76	8
Regulatory Asset for Under-Recovered Fuel Costs	31	37
Prepayments and Other Current Assets	26	14
TOTAL CURRENT ASSETS	563	383
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,118	4,365
Transmission	1,506	1,433
Distribution	4,130	3,987
Other Property, Plant and Equipment	1,302	1,292
Construction Work in Progress	864	635
Total Property, Plant and Equipment	11,920	11,712
Accumulated Depreciation and Amortization	2,498	2,748
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	9,422	8,964
OTHER NONCURRENT ASSETS		
Regulatory Assets	693	637
Employee Benefits and Pension Assets	96	95
Operating Lease Assets	122	126
Deferred Charges and Other Noncurrent Assets	50	13
TOTAL OTHER NONCURRENT ASSETS	961	871
TOTAL ASSETS	$ 10,946	$ 10,218

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2026 and December 31, 2025
(in millions, except per-share and share amounts)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT LIABILITIES		
Advances from Affiliates	$ 394	$ 171
Accounts Payable:		
General	367	339
Affiliated Companies	136	87
Long-term Debt Due Within One Year – Nonaffiliated	51	51
Risk Management Liabilities	22	27
Customer Deposits	117	115
Accrued Taxes	86	37
Accrued Interest	66	67
Obligations Under Operating Leases	12	11
Other Current Liabilities	118	104
TOTAL CURRENT LIABILITIES	1,369	1,009
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,476	3,475
Deferred Income Taxes	1,156	1,113
Regulatory Liabilities and Deferred Investment Tax Credits	712	717
Asset Retirement Obligations	157	136
Obligations Under Operating Leases	119	122
Deferred Credits and Other Noncurrent Liabilities	162	33
TOTAL NONCURRENT LIABILITIES	5,782	5,596
TOTAL LIABILITIES	7,151	6,605
Rate Matters (Note 4)		
Commitments, Guarantees 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	157
Paid-in Capital	1,831	1,718
Retained Earnings	1,805	1,736
Accumulated Other Comprehensive Income (Loss)	2	2
TOTAL COMMON SHAREHOLDER'S EQUITY	3,795	3,613
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,946	$ 10,218

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

PUBLIC SERVICE COMPANY OF OKLAHOMA
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
OPERATING ACTIVITIES		
Net Income	$ 69	$ 91
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	147	136
Deferred Income Taxes	34	40
Allowance for Equity Funds Used During Construction	(5)	(6)
Mark-to-Market of Risk Management Contracts	(1)	(73)
Property Taxes	(37)	(32)
Deferred Fuel Over/Under-Recovery, Net	6	(74)
Change in Other Regulatory Assets	(6)	(25)
Change in Other Noncurrent Assets	(26)	3
Change in Other Noncurrent Liabilities	151	(8)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(83)	(39)
Fuel, Materials and Supplies	(21)	3
Accounts Payable	114	121
Accrued Taxes, Net	(19)	45
Other Current Assets	(11)	(16)
Other Current Liabilities	(34)	(1)
Net Cash Flows from Operating Activities	278	165
INVESTING ACTIVITIES		
Construction Expenditures	(615)	(325)
Change in Advances to Affiliates, Net	—	232
Acquisitions of Generation Facilities	—	(1,359)
Other Investing Activities	3	1
Net Cash Flows Used for Investing Activities	(612)	(1,451)
FINANCING ACTIVITIES		
Capital Contribution from Parent	113	300
Issuance of Long-term Debt – Nonaffiliated	—	794
Change in Advances from Affiliates, Net	223	320
Retirement of Long-term Debt – Nonaffiliated	—	(125)
Other Financing Activities	(1)	(1)
Net Cash Flows from Financing Activities	335	1,288
Net Increase in Cash and Cash Equivalents	1	2
Cash and Cash Equivalents at Beginning of Period	2	2
Cash and Cash Equivalents at End of Period	$ 3	$ 4
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 86	$ 47
Construction Expenditures Included in Current Liabilities as of June 30,	184	91

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

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,	
	2026	**2025**	**2026**	**2025**
	(in millions of KWhs)			
Retail:				
Residential	1,416	1,365	2,847	2,968
Commercial	1,431	1,415	2,703	2,660
Industrial	1,358	1,327	2,583	2,508
Miscellaneous	17	18	33	34
Total Retail	4,222	4,125	8,166	8,170
Wholesale (a)	1,104	1,251	2,379	2,743
Total KWhs	5,326	5,376	10,545	10,913

(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,	
	2026	**2025**	**2026**	**2025**
	(in degree days)			
Actual – Heating	2	9	496	726
Normal – Heating	24	24	720	714
Actual – Cooling	888	948	1,038	1,044
Normal – Cooling	781	770	831	816

Southwestern Electric Power Company Consolidated
Reconciliation of 2025 to 2026
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

	Three Months Ended June 30,	Six Months Ended June 30,
2025 Earnings Attributable to Common Shareholder	$ 116	$ 164
Changes in Revenues:		
Retail Revenues (a)	21	42
Off-system Sales	1	1
Transmission Revenues	(8)	11
Other Revenues	4	4
Total Change in Revenues	18	58
Changes in Expenses and Other:		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	36	56
Other Operation and Maintenance	(25)	(57)
Asset Impairments and Other Related Charges	—	(31)
Depreciation and Amortization	(15)	(38)
Taxes Other Than Income Taxes	(6)	(8)
Interest Income	(2)	(2)
Allowance for Equity Funds Used During Construction	3	8
Non-Service Cost Components of Net Periodic Benefit Cost	—	(1)
Interest Expense	(25)	(36)
Total Change in Expenses and Other	(34)	(109)
Income Tax Benefit	(14)	29
Equity Earnings of Unconsolidated Subsidiary	(1)	(1)
Net Income Attributable to Noncontrolling Interest	1	1
2026 Earnings Attributable to Common Shareholder	$ 86	$ 142

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

Second Quarter of 2026 Compared to Second Quarter of 2025

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

- **Retail Revenues** increased $21 million primarily due to the following:
  - A $34 million increase in weather-normalized revenues in all classes.
  - A $27 million increase in rider revenues across all jurisdictions.
  - A $22 million increase due to the Arkansas base rate case.

  These increases were partially offset by:
  - A $33 million decrease due to an $18 million decrease primarily as a result of lower authorized rates in Louisiana and a $15 million decrease in fuel revenue due to a refund of the Texas over-recovered fuel balance.
  - A $23 million decrease due to a probable credit to certain existing wholesale generation customers.
  - A $7 million decrease in weather-related usage primarily due to a 6% decrease in cooling degree days.
- **Transmission Revenues** decreased $8 million primarily due to the following:
  - A $27 million decrease due to the June 2025 FERC order related to the treatment of NOLCs in transmission formula rates.

  This decrease was partially offset by:
  - A $19 million increase due to continued transmission investment.

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

- **Purchased Electricity, Fuel and Other Consumables Used for Electric Generation** expenses decreased $36 million primarily due to the following:
  - A $30 million decrease due to a decrease in the deferred fuel costs related to a $15 million Texas fuel refund and a $15 million decrease primarily due to lower authorized rates in Louisiana.
  - An $8 million decrease primarily due to decreased purchased power prices and increased wind generation.

  These decreases were partially offset by:
  - A $7 million increase in recoverable PTCs.
- **Other Operation and Maintenance** expenses increased $25 million primarily due to the following:
  - A $7 million increase in distribution expenses primarily due to overhead line maintenance.
  - A $6 million increase in generation expenses primarily due to the acquisition of the Wagon Wheel Wind Facility.
  - A $5 million increase due to the partial write-off of previously capitalized vegetation management costs as a result of SWEPCo's FERC audit.
- **Depreciation and Amortization** expenses increased $15 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $6 million primarily due to an increase in property taxes.
- **Interest Expense** increased $25 million primarily due to higher long-term debt balances.
- **Income Tax Benefit** decreased $14 million primarily due to the following:
  - A $42 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.

  This decrease was partially offset by:
  - A $24 million increase due to an increase in PTCs.

Six Months Ended June 30, 2026 Compared to Six Months Ended June 30, 2025

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

- **Retail Revenues** increased $42 million primarily due to the following:
  - A $53 million increase in weather-normalized revenues in all classes.
  - A $52 million increase in rider revenues across all jurisdictions.
  - A $34 million increase due to the Arkansas base rate case.

  These increases were partially offset by:
  - A $60 million decrease in fuel revenue due to a $43 million refund of the Texas over-recovered fuel balance and a $17 million decrease primarily due to lower authorized rates in Arkansas and Louisiana.
  - A $23 million decrease due to a probable credit to certain existing wholesale generation customers.
  - A $17 million decrease in weather-related usage primarily due to a 32% decrease in heating degree days.
- **Transmission Revenues** increased $11 million primarily due to the following:
  - A $35 million increase due to continued transmission investment.

  This increase was partially offset by:
  - A $27 million decrease 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 decreased $56 million primarily due to the following:
  - A $55 million decrease due to a decrease in the deferred fuel costs related to a $43 million Texas fuel refund and a $12 million decrease primarily due to lower authorized rates in Arkansas and Louisiana.
  - A $14 million decrease primarily due to decreased purchased power prices and increased wind generation.
  - An $8 million decrease due to prior year Louisiana and Texas fuel disallowances.

  These decreases were partially offset by:
  - A $15 million increase in recoverable PTCs.
  - A $12 million increase in non-recoverable fuel costs primarily in Louisiana.
- **Other Operation and Maintenance** expenses increased $57 million primarily due to the following:
  - A $14 million increase in distribution expenses primarily due to overhead line maintenance.
  - A $13 million increase in transmission expenses primarily due to:
    - A $23 million increase in SPP expenses.

    This increase was partially offset by:
    - A $10 million decrease due to the June 2025 FERC order related to the treatment of NOLC's in transmission formula rates.

  - A $12 million increase in generation expenses primarily due to the acquisition of the Wagon Wheel Wind Facility.
  - A $6 million increase in employee-related costs.
  - A $6 million increase due to the partial write-off of previously capitalized vegetation management costs as a result of SWEPCo's FERC audit.
- **Asset Impairments and Other Related Charges** increased $31 million due to the probable, partial disallowance of the Pirkey Plant net book value in the 2025 Texas Base Rate Case.
- **Depreciation and Amortization** expenses increased $38 million primarily due to the following:
  - A $30 million increase due to a higher depreciable base.
  - A $7 million increase primarily due to higher over-recovery of costs and allowable returns associated with the generation rider.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to an increase in property taxes.
- **Allowance for Equity Funds Used During Construction** increased $8 million primarily due to a higher AFUDC base.
- **Interest Expense** increased $36 million primarily due to the following:
  - A $27 million increase due to higher long-term debt balances.
  - A $7 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 $5 million increase related to the Texas tax normalization rider amortization.
- **Income Tax Benefit** increased $29 million primarily due to the following:
  - A $56 million increase due to an increase in PTCs.
  - An $11 million increase due to a decrease in pretax book income.

  These increases were partially offset by:
  - A $42 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.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
REVENUES				
Electric Generation, Transmission and Distribution	$ 561	$ 545	$ 1,109	$ 1,062
Sales to AEP Affiliates	25	24	47	35
Other Revenues	2	1	3	4
TOTAL REVENUES	588	570	1,159	1,101
EXPENSES				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	156	192	327	383
Other Operation	126	108	244	205
Maintenance	57	50	103	85
Asset Impairments and Other Related Charges	—	—	31	—
Depreciation and Amortization	123	108	244	206
Taxes Other Than Income Taxes	35	29	72	64
TOTAL EXPENSES	497	487	1,021	943
OPERATING INCOME	91	83	138	158
Other Income (Expense):				
Interest Income	1	3	3	5
Allowance for Equity Funds Used During Construction	7	4	15	7
Non-Service Cost Components of Net Periodic Benefit Cost	2	2	3	4
Interest Expense	(59)	(34)	(109)	(73)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	42	58	50	101
Income Tax Expense (Benefit)	(44)	(58)	(93)	(64)
Equity Earnings of Unconsolidated Subsidiary	—	1	—	1
NET INCOME	86	117	143	166
Net Income Attributable to Noncontrolling Interest	—	1	1	2
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 86	$ 116	$ 142	$ 164

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

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	**2025**	**2026**	**2025**
Net Income	$ 86	$ 117	$ 143	$ 166
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2026 and 2025, Respectively, and $0 and $0 for the Six Months Ended June 30, 2026 and 2025, Respectively	—	—	—	—
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $0 for the Three Months Ended June 30, 2026 and 2025, Respectively, and $0 and $0 for the Six Months Ended June 30, 2026 and 2025, Respectively	—	—	—	—
TOTAL COMPREHENSIVE INCOME	86	117	143	166
Total Comprehensive Income Attributable to Noncontrolling Interest	—	1	1	2
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 86	$ 116	$ 142	$ 164

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Six Months Ended June 30, 2026 and 2025
(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, 2024	$ —	$ 1,550	$ 2,352	$ 3	$ —	$ 3,905
Common Stock Dividends – Nonaffiliated					(1)	(1)
Net Income			48		1	49
TOTAL EQUITY – MARCH 31, 2025	—	1,550	2,400	3	—	3,953
Capital Contribution from Parent		450				450
Common Stock Dividends – Nonaffiliated					(1)	(1)
Net Income			116		1	117
TOTAL EQUITY – JUNE 30, 2025	$ —	$ 2,000	$ 2,516	$ 3	$ —	$ 4,519
TOTAL EQUITY – DECEMBER 31, 2025	$ —	$ 2,151	$ 2,740	$ 8	$ —	$ 4,899
Capital Contribution from Parent		128				128
Common Stock Dividends – Nonaffiliated					(1)	(1)
Net Income			56		1	57
TOTAL EQUITY – MARCH 31, 2026	—	2,279	2,796	8	—	5,083
Capital Contribution from Parent		81				81
Net Income			86		—	86
TOTAL EQUITY – JUNE 30, 2026	$ —	$ 2,360	$ 2,882	$ 8	$ —	$ 5,250

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
June 30, 2026 and December 31, 2025
(in millions)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2	$ 2
Restricted Cash (June 30, 2026 and December 31, 2025 Amounts Include $14 and $15, Respectively, Related to Storm Recovery Funding)	14	15
Advances to Affiliates	—	23
Accounts Receivable:		
Customers	50	63
Affiliated Companies	116	91
Miscellaneous	11	10
Total Accounts Receivable	177	164
Fuel	91	83
Materials and Supplies (June 30, 2026 and December 31, 2025 Amounts Include $1 and $1, Respectively, Related to Sabine)	96	88
Risk Management Assets	42	35
Accrued Tax Benefits	110	17
Regulatory Asset for Under-Recovered Fuel Costs	94	115
Prepayments and Other Current Assets	15	14
TOTAL CURRENT ASSETS	641	556
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,650	6,621
Transmission	3,397	3,302
Distribution	3,366	3,242
Other Property, Plant and Equipment (June 30, 2026 and December 31, 2025 Amounts Include $84 and $125, Respectively, Related to Sabine)	932	942
Construction Work in Progress	1,061	712
Total Property, Plant and Equipment	15,406	14,819
Accumulated Depreciation and Amortization (June 30, 2026 and December 31, 2025 Amounts Include $84 and $125, Respectively, Related to Sabine)	3,590	3,478
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	11,816	11,341
OTHER NONCURRENT ASSETS		
Regulatory Assets	955	903
Securitized Assets (June 30, 2026 and December 31, 2025 Amounts Include $307 and $315, Respectively, Related to Storm Recovery Funding)	307	315
Deferred Charges and Other Noncurrent Assets	465	409
TOTAL OTHER NONCURRENT ASSETS	1,727	1,627
TOTAL ASSETS	$ 14,184	$ 13,524

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
June 30, 2026 and December 31, 2025
(in millions, except per-share and share amounts)
(Unaudited)

	June 30, 2026	December 31, 2025
CURRENT LIABILITIES		
Advances from Affiliates	$ 311	$ —
Accounts Payable:		
General	457	392
Affiliated Companies	80	89
Short-term Debt – Nonaffiliated	3	3
Long-term Debt Due Within One Year – Nonaffiliated (June 30, 2026 and December 31, 2025 Amounts Include $17 and $17, Respectively, Related to Storm Recovery Funding)	417	917
Risk Management Liabilities	10	9
Customer Deposits	84	79
Accrued Taxes	131	68
Accrued Interest	65	49
Obligations Under Operating Leases	5	7
Provision for Refund	83	81
Other Current Liabilities	173	191
TOTAL CURRENT LIABILITIES	1,819	1,885
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (June 30, 2026 and December 31, 2025 Amounts Include $296 and $304, Respectively, Related to Storm Recovery Funding)	4,441	3,057
Long-term Debt – Affiliated	—	1,000
Deferred Income Taxes	1,516	1,458
Regulatory Liabilities and Deferred Investment Tax Credits	507	531
Asset Retirement Obligations	238	252
Employee Benefits and Pension Obligations	42	39
Obligations Under Operating Leases	192	195
Provision for Refund	6	47
Storm Reserve	110	108
Deferred Credits and Other Noncurrent Liabilities	63	53
TOTAL NONCURRENT LIABILITIES	7,115	6,740
TOTAL LIABILITIES	8,934	8,625
Rate Matters (Note 4)		
Commitments, Guarantees and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 3,680 Shares		
Outstanding – 3,680 Shares	—	—
Paid-in Capital	2,360	2,151
Retained Earnings	2,882	2,740
Accumulated Other Comprehensive Income (Loss)	8	8
TOTAL COMMON SHAREHOLDER'S EQUITY	5,250	4,899
Noncontrolling Interest	—	—
TOTAL EQUITY	5,250	4,899
TOTAL LIABILITIES AND EQUITY	$ 14,184	$ 13,524

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2026 and 2025
(in millions)
(Unaudited)

	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
OPERATING ACTIVITIES		
Net Income	$ 143	$ 166
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	244	206
Deferred Income Taxes	26	18
Asset Impairments and Other Related Charges	31	—
Allowance for Equity Funds Used During Construction	(15)	(7)
Mark-to-Market of Risk Management Contracts	(5)	(51)
Pension Contributions to Qualified Plan Trust	—	(9)
Property Taxes	(55)	(45)
Deferred Fuel Over/Under-Recovery, Net	46	64
Change in Regulatory Assets	(89)	(33)
Change in Other Noncurrent Assets	(13)	6
Change in Other Noncurrent Liabilities	(42)	(57)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(9)	8
Fuel, Materials and Supplies	(16)	(6)
Accounts Payable	41	90
Accrued Taxes, Net	(30)	32
Other Current Assets	2	(20)
Other Current Liabilities	(6)	(4)
Net Cash Flows from Operating Activities	253	358
INVESTING ACTIVITIES		
Construction Expenditures	(692)	(440)
Change in Advances to Affiliates, Net	23	(76)
Other Investing Activities	13	5
Net Cash Flows Used for Investing Activities	(656)	(511)
FINANCING ACTIVITIES		
Capital Contribution from Parent	209	450
Issuance of Long-term Debt – Nonaffiliated	1,393	—
Change in Short-term Debt – Nonaffiliated	—	(4)
Change in Advances from Affiliates, Net	311	(275)
Retirement of Long-term Debt – Nonaffiliated	(508)	—
Retirement of Long-term Debt – Affiliated	(1,000)	—
Dividends Paid on Common Stock – Nonaffiliated	(1)	(2)
Other Financing Activities	(2)	—
Net Cash Flows from Financing Activities	402	169
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(1)	16
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	17	5
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 16	$ 21
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 95	$ 72
Construction Expenditures Included in Current Liabilities as of June 30,	237	99

See Condensed Notes to Condensed Financial Statements of Registrants beginning on page 106.

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, 2026 is not necessarily indicative of results that may be expected for the year ending December 31, 2026. The condensed financial statements are unaudited and should be read in conjunction with the audited 2025 financial statements and notes thereto, which are included in the 2025 Annual Reports.

Change in Presentation

In 2025, the Company changed its rounding presentation in the Registrant's financial statements and accompanying tabular footnote disclosures to the nearest whole number in millions, except per share data. The change had no material impact on previously reported financial information, however, certain amounts reported for prior periods may differ by insignificant amounts due to the rounding presentation. In addition, historical percentages and per share amounts presented may not recalculate due to rounding. This change does not impact the comparability of the Registrant's financial statements and related disclosures.

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 12 - 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,			
	2026		2025	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 713		$ 1,226	
Weighted-Average Number of Basic AEP Common Shares Outstanding	544.2	$ 1.31	534.3	$ 2.29
Weighted-Average Dilutive Effect	6.4	(0.01)	2.1	—
Weighted-Average Number of Diluted AEP Common Shares Outstanding	550.6	$ 1.30	536.4	$ 2.29

	Six Months Ended June 30,			
	2026		2025	
	(in millions, except per share data)			
		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,587		$ 2,026	
Weighted-Average Number of Basic AEP Common Shares Outstanding	543.1	$ 2.92	533.8	$ 3.80
Weighted-Average Dilutive Effect	5.7	(0.03)	1.7	(0.02)
Weighted-Average Number of Diluted AEP Common Shares Outstanding	548.8	$ 2.89	535.5	$ 3.78

There were no antidilutive shares outstanding as of June 30, 2026 and 2025.

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, 2026			
	AEP	**AEP Texas**	**APCo**	**SWEPCo**
	(in millions)			
Cash and Cash Equivalents	$ 375	$ —	$ 4	$ 2
Restricted Cash	72	13	25	14
Total Cash, Cash Equivalents and Restricted Cash	$ 447	$ 13	$ 29	$ 16

	December 31, 2025			
	AEP	**AEP Texas**	**APCo**	**SWEPCo**
	(in millions)			
Cash and Cash Equivalents	$ 197	$ —	$ 5	$ 2
Restricted Cash	71	14	18	15
Total Cash, Cash Equivalents and Restricted Cash	$ 268	$ 14	$ 23	$ 17

Supplementary Cash Flow Information (Applies to AEP)

	Six Months Ended June 30,	
Cash Flow Information	**2026**	**2025**
	(in millions)	
Cash Paid for:		
Interest, Net of Capitalized Amounts	$ 1,083	$ 946
Noncash Investing and Financing Activities:		
Construction Expenditures Included in Current Liabilities as of June 30,	2,005	1,059
Contribution in Aid of Construction Advances in Current Assets as of June 30,	112	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of June 30,	33	33

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

In March 2024, the SEC adopted final rules that would require registrants to disclose certain climate-related information in registration statements and annual reports. 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. In March 2025, the SEC announced that it voted to end its defense of the final climate disclosure rules. In April 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. In July 2025, the SEC filed a status report stating that it does not intend to review or reconsider the rules and asked the Court of Appeals to make a ruling on the case. In September 2025, the Court of Appeals issued an order holding the case in abeyance until the SEC either formally defends the rules or initiates a new rulemaking process for reconsideration. In May 2026, the SEC formally proposed to rescind its climate-related disclosure rules. The proposal is subject to notice-and-comment rulemaking before a final rule can be approved.

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.

ASU 2025-06 "Intangibles—Goodwill and Other—Internal-Use Software" (ASU 2025-06)

In September 2025, the FASB issued ASU 2025-06, the intent of which is to modernize the cost capitalization threshold for internal-use software development costs by removing all references to software project development stages and providing new guidance on how to evaluate whether the probable-to-complete recognition threshold has been met for the commencement of capitalization of eligible costs.

The amendments in the new standard may be applied on either a retrospective, prospective or modified prospective basis for public business entities for fiscal years beginning after December 15, 2027 with early adoption permitted. Management elected to early adopt this standard prospectively beginning on January 1, 2026. The adoption of the new standard did not have a material impact on the results of operations, statements of financial position or cash flows.

ASU 2026-02 "Environmental Credits and Environmental Credit Obligations" (ASU 2026-02)

In May 2026, the FASB issued ASU 2026-02, the intent of which is to improve the financial accounting for and disclosure of environmental credits and environmental credit obligations. The new standard establishes guidance on the recognition, measurement, presentation, and disclosure requirements for all public business entities that generate, purchase, or receive environmental credits or have a regulatory compliance obligation that may be settled with environmental credits.

The amendments in the new standard are effective for annual reporting periods beginning after December 15, 2027, and interim reporting periods within those annual reporting periods. Early adoption is permitted as of the beginning of an annual reporting period and should be applied on a retrospective basis. Management is currently evaluating the impact of this ASU on its consolidated financial statements and related disclosures.

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, 2026	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of March 31, 2026	$ 63	$ (1)	$ (40)	$ 22
Change in Fair Value Recognized in AOCI, Net of Tax	20	—	—	20
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	2	—	—	2
Amortization of Actuarial (Gains) Losses	—	—	2	2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2	—	2	4
Income Tax (Expense) Benefit	—	—	1	1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	2	—	1	3
Net Current Period Other Comprehensive Income	22	—	1	23
Balance in AOCI as of June 30, 2026	$ 85	$ (1)	$ (39)	$ 45

Three Months Ended June 30, 2025	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
		(in millions)		
Balance in AOCI as of March 31, 2025	$ 124	$ 1	$ (104)	$ 21
Change in Fair Value Recognized in AOCI, Net of Tax	(36)	—	—	(36)
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	5	—	—	5
Interest Expense (a)	—	(1)	—	(1)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	5	(1)	—	4
Income Tax (Expense) Benefit	1	—	—	1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	4	(1)	—	3
Net Current Period Other Comprehensive Loss	(32)	(1)	—	(33)
Balance in AOCI as of June 30, 2025	$ 92	$ —	$ (104)	$ (12)

Six Months Ended June 30, 2026	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of December 31, 2025	$ 78	$ (1)	$ (41)	$ 36
Change in Fair Value Recognized in AOCI, Net of Tax	45	—	—	45
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(48)	—	—	(48)
Amortization of Actuarial (Gains) Losses	—	—	3	3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(48)	—	3	(45)
Income Tax (Expense) Benefit	(10)	—	1	(9)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(38)	—	2	(36)
Net Current Period Other Comprehensive Income	7	—	2	9
Balance in AOCI as of June 30, 2026	$ 85	$ (1)	$ (39)	$ 45

Six Months Ended June 30, 2025	Cash Flow Hedges Commodity	Cash Flow Hedges Interest Rate	Pension and OPEB	Total
	(in millions)			
Balance in AOCI as of December 31, 2024	$ 99	$ 3	$ (105)	$ (3)
Change in Fair Value Recognized in AOCI, Net of Tax	2	(1)	—	1
Amount of (Gain) Loss Reclassified from AOCI				
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation (a)	(12)	—	—	(12)
Interest Expense (a)	—	(2)	—	(2)
Amortization of Actuarial (Gains) Losses	—	—	1	1
Reclassifications from AOCI, before Income Tax Expense	(12)	(2)	1	(13)
Income Tax Expense	(3)	—	—	(3)
Reclassifications from AOCI, Net of Income Tax Expense	(9)	(2)	1	(10)
Net Current Period Other Comprehensive Income (Loss)	(7)	(3)	1	(9)
Balance in AOCI as of June 30, 2025	$ 92	$ —	$ (104)	$ (12)

(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 2025 Annual Report, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The Rate Matters note within the 2025 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 2026 and updates the 2025 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 regularly 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 Unit that has been Retired and Related Fuel Operations

SWEPCo

In March 2023, the Pirkey Plant was retired. SWEPCo is recovering, or is seeking recovery of, the remaining net book value of Pirkey Plant non-fuel costs. As of June 30, 2026, SWEPCo's share of the net investment in the Pirkey Plant was $171 million, including materials and supplies, net of cost of removal. Fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions.

As part of the 2021 Arkansas Base Rate Case, the APSC granted SWEPCo regulatory asset treatment of the Pirkey Plant net investment. SWEPCo requested recovery including a weighted average cost of capital carrying charge in its 2025 Arkansas Base Rate Case. In January 2026, the APSC approved a settlement agreement providing for the recovery of the Pirkey Plant net investment over 10 years with a 3% return, and the agreement also included a provision that the retirement of the Pirkey Plant was prudent.

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.

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 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 July 2023 PFD conclusion. SWEPCo requested recovery of the Texas jurisdictional share of the remaining net book value of the Pirkey Plant in its 2025 Texas Base Rate Case. In April 2026, a unanimous settlement in principle was reached related to the 2025 Texas Base Rate Case. In the first quarter of 2026, SWEPCo recorded approximately $31 million for a probable, partial regulatory disallowance of the Pirkey Plant. See the "2025 Texas Base Rate Case" section below for additional information. As of June 30, 2026, the Texas jurisdictional share of the net book value of the Pirkey Plant was $46 million. To the extent the PUCT does not accept the settlement and any costs included in this filing are not approved for recovery as a result of the final PUCT order, 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, which the ODEQ has submitted. In anticipation of approval from the Federal EPA, PSO began operating Northeastern Plant, Unit 3 on natural gas in January 2026. In the first quarter of 2026, PSO retired $325 million of coal-related assets at Northeastern Plant, Unit 3, resulting in a decrease to both Total Property, Plant and Equipment and Accumulated Depreciation and Amortization. As of June 30, 2026, the unrecovered value of these assets was $151 million, inclusive of ARO costs, which PSO is currently collecting in rates.

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 CCN with the APSC, LPSC and PUCT to convert Welsh Plant, Units 1 and 3 to natural gas in 2028 and 2027, respectively. In February 2026, the APSC issued an order approving the application for a CCN. In July 2026, SWEPCo, PUCT staff and certain intervenors filed an unopposed stipulation and settlement agreement with the PUCT agreeing the application for a CCN should be approved. Additionally, in July 2026, SWEPCo and the LPSC staff filed a joint stipulation and term sheet with the LPSC agreeing the application for a CCN should be approved.

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of June 30, 2026, of generating facilities planned for 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	$ 53	$ 251	$ 21 (b)	2026	(c)	$ 11
Welsh Plant, Units 1 and 3	230	249	55 (d)	2028 (e)	(f)	44

(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.

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

	AEP	
Noncurrent Regulatory Assets	**June 30, 2026**	**December 31, 2025**
	(in millions)	
Regulatory Assets Currently Earning a Return		
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 249	$ 220
UTM Deferred Costs	65	56
Pirkey Plant Accelerated Depreciation	61	93
Storm-Related Costs	47	43
System Resiliency Plan Deferred Costs - Texas	46	17
Other Regulatory Assets Pending Final Regulatory Approval	5	6
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (a)	300	191
Plant Retirement Costs – Asset Retirement Obligation Costs (b)	283	257
NOLC Costs (c)	85	89
2024-2025 Virginia Biennial Under-Earnings (d)	51	172
Vegetation Management Costs	33	—
Deferred Pension and OPEB Costs	36	27
Other Regulatory Assets Pending Final Regulatory Approval	165	136
Total Regulatory Assets Pending Final Regulatory Approval	$ 1,426	$ 1,307

(a) In March 2026, the WVPSC issued a financing order approving a securitization that includes $40 million of West Virginia jurisdictional storm operation and maintenance costs that are subject to a final review by the WVPSC after bond pricing.
(b) Includes ARO adjustment related to the revised CCR Rule to be addressed in future regulatory proceedings. See "Federal EPA's Revised CCR Rule" section of Note 5 for additional information.
(c) Approved for collection through rates, subject to refund, for the Oklahoma and SWEPCo-Texas jurisdictions.
(d) In May 2026, APCo issued securitization bonds that included $141 million of storm operation and maintenance costs.

	AEP Texas	
Noncurrent Regulatory Assets	**June 30, 2026**	**December 31, 2025**
	(in millions)	
Regulatory Assets Currently Earning a Return		
UTM Deferred Costs	$ 65	$ 56
Storm-Related Costs	41	41
System Resiliency Plan Deferred Costs	23	17
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	39	31
Deferred Pension and OPEB Costs	36	27
UTM Deferred Costs	7	—
Other Regulatory Assets Pending Final Regulatory Approval	10	9
Total Regulatory Assets Pending Final Regulatory Approval	$ 221	$ 181

Noncurrent Regulatory Assets	AEPTCo June 30, 2026	AEPTCo December 31, 2025
	(in millions)	
Regulatory Assets Currently Earning a Return		
Income Taxes, Net	$ 9	$ 9
Total Regulatory Assets Pending Final Regulatory Approval	$ 9	$ 9

Noncurrent Regulatory Assets	APCo June 30, 2026	APCo December 31, 2025
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 2	$ 2
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs (a)	185	169
Storm-Related Costs – West Virginia (b)	64	39
2024-2025 Virginia Biennial Under-Earnings (c)	51	172
Vegetation Management Costs	13	—
2026-2027 Virginia Biennial Under-Earnings	18	—
Pension Settlement	16	16
Virginia Corporate Alternative Minimum Tax	—	13
West Virginia Corporate Alternative Minimum Tax	—	11
Other Regulatory Assets Pending Final Regulatory Approval	27	18
Total Regulatory Assets Pending Final Regulatory Approval	$ 376	$ 440

(a) Includes ARO adjustment related to the revised CCR Rule to be addressed in a future regulatory proceeding. See "Federal EPA's Revised CCR Rule" section of Note 5 for additional information.

(b) In March 2026, the WVPSC issued a financing order approving a securitization that includes $40 million of West Virginia jurisdictional storm operation and maintenance costs that are subject to a final review by the WVPSC after bond pricing.

(c) In May 2026, APCo issued securitization bonds that included $141 million of storm operation and maintenance costs. See "2025 Virginia Securitization Filing" section below for additional information.

Noncurrent Regulatory Assets	I&M June 30, 2026	I&M December 31, 2025
	(in millions)	
Regulatory Assets Currently Earning a Return		
Other Regulatory Assets Pending Final Regulatory Approval	$ 4	$ 4
Regulatory Assets Currently Not Earning a Return		
Plant Retirement Costs – Asset Retirement Obligation Costs (a)	81	78
Storm-Related Costs – Indiana	46	29
Other Regulatory Assets Pending Final Regulatory Approval	7	7
Total Regulatory Assets Pending Final Regulatory Approval	$ 138	$ 118

(a) Includes ARO adjustment related to the revised CCR Rule to be addressed in a future regulatory proceeding. See "Federal EPA's Revised CCR Rule" section of Note 5 for additional information.

Noncurrent Regulatory Assets	PSO June 30, 2026	PSO December 31, 2025
	(in millions)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs	$ 34	$ 25
Generation PBA and Delayed Retirement Deferral	26	13
Oklahoma Senate Bill 998 Deferral	24	9
NOLC Costs (a)	19	23
Plant Retirement Costs – Asset Retirement Obligation Costs (b)	12	6
Other Regulatory Assets Pending Final Regulatory Approval	1	8
Total Regulatory Assets Pending Final Regulatory Approval	$ 116	$ 84

(a) Approved for collection through rates, subject to refund.
(b) Includes ARO adjustment related to the revised CCR Rule to be addressed in a future regulatory proceeding. See "Federal EPA's Revised CCR Rule" section of Note 5 for additional information.

Noncurrent Regulatory Assets	SWEPCo June 30, 2026	SWEPCo December 31, 2025
	(in millions)	
Regulatory Assets Currently Earning a Return		
Welsh Plant, Units 1 and 3 Accelerated Depreciation	$ 249	$ 220
Pirkey Plant Accelerated Depreciation	61	93
System Resiliency Plan Deferred Costs - Texas	23	1
Income Taxes, Net	7	—
Other Regulatory Assets Pending Final Regulatory Approval	5	2
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs - Louisiana, Texas	92	43
NOLC Costs (a)	65	66
Other Regulatory Assets Pending Final Regulatory Approval	22	20
Total Regulatory Assets Pending Final Regulatory Approval	$ 524	$ 445

(a) Approved for collection through rates, subject to refund, for Texas jurisdiction.

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

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

AEP Texas Interim Transmission and Distribution Rates

Through June 30, 2026, AEP Texas' cumulative revenues from transmission and distribution interim base rate increases that are subject to review are estimated to be approximately $223 million. AEP Texas recognized an $8 million provision for refund related to the UTM filing for amounts collected through the second quarter of 2026. 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.

2025 UTM Filing

In October 2025, AEP Texas submitted its first filing with the PUCT seeking recovery of eligible costs through the UTM. In March 2026, a Texas ALJ issued a PFD recommending partial disallowance of the requested amounts which was based on an interpretation of a later effective date for eligible UTM deferrals. In April 2026, AEP Texas filed responses reflective of the legislative intent of Texas House Bill 5247 (2025). In May 2026, the PUCT Chairman issued a Commissioner Memorandum agreeing with the ALJ's PFD and ordered the PUCT staff to complete a calculation to confirm the final disallowance amount. Completion of the Commission-required calculation and final order are expected in the third quarter of 2026. In conjunction with the Commissioner Memorandum, AEP Texas recognized an unfavorable pretax impact of $23 million in May 2026 attributable to a portion of the deferrals included in the UTM application period.

As of June 30, 2026, AEP Texas had deferred approximately $72 million of eligible costs as a regulatory asset of which $65 million will be included in AEP Texas' next UTM application. Investments included in the UTM and the existing capital tracker filings remain subject to prudency review in the utility's next base rate case proceeding before the PUCT. If any of these deferred costs or investments 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)

2021-2023 ENEC Remand Cases

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 remand 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.

In August 2025, WVPSC staff and an intervening party submitted testimony recommending the continued disallowance of $232 million of ENEC under-recovered costs as of February 28, 2023, with the intervening party recommending that the WVPSC consider a larger disallowance based on alleged imprudence of coal procurement.

A hearing on the 2021-2023 ENEC remand cases was held in October 2025. If any additional 2021-2023 ENEC costs are not recoverable or refunds are ordered, it would reduce future net income and cash flows and impact financial condition.

2026 ENEC Update Filing

In April 2026, the Companies submitted their annual ENEC update filing with the WVPSC for the annual review period ended February 28, 2026, proposing a $21 million annual increase in ENEC rates when compared to existing ENEC rates. The Companies proposed that this increase in ENEC rates become effective September 1, 2026 with the increase in ENEC rates based on the Companies' projected costs for period September 2026 through August 2027. The Companies' ENEC update filing also included a projected August 31, 2026 ENEC under-recovery balance of $597 million ($285 million related to APCo). This projected ENEC under-recovery balance included recovery of final true-ups of the Companies' West Virginia Modified Rate Base Cost (MRBC), Vegetation Management and Broadband surcharges as well as continued deferral of the Companies' West Virginia base rate increase that was ordered by the WVPSC in August 2025 and February 2026. See "West Virginia Modified Rate Base Cost (MRBC) Surcharge Update Filing" section below for further details. The Companies proposed that this projected August 31, 2026 ENEC under-recovery balance of $597 million be included in the final combined balance approved by the WVPSC for securitization in late 2026.

In June 2026, the Companies, Staff and intervening parties filed a settlement with the WVPSC which recommended a projected August 31, 2026 ENEC under-recovery balance of $594 million ($275 million related to APCo) to be eligible for securitization. The settlement further recommended that the ENEC annual review period ending February 28, 2026 remain open until the Companies' next ENEC proceeding.

In July 2026, the WVPSC issued an order on the June 2026 settlement, approving a $593 million projected August 31, 2026 ENEC under-recovery balance ($274 million related to APCo) that will be included in the Companies' overall balance to be securitized. The WVPSC's order also approved an updated $2.7 billion overall balance to be securitized ($1.7 billion related to

APCo) as further described in the "2025 West Virginia Securitization Filing" section below. It is currently estimated that this securitization will take place in the fourth quarter of 2026.

For the Companies' ongoing filing to determine updated ENEC rates effective September 1, 2026, an intervening party submitted testimony in July 2026 alleging that the Companies were imprudent in their coal procurement practices, but did not recommend a specific cost disallowance. It is anticipated that the WVPSC will issue an order on this ENEC update filing in the third quarter of 2026.

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

2024 West Virginia Base Rate Case

In September 2025, and in response to the WVPSC's August 2025 order on the Companies' 2024 West Virginia Base Rate Case, petitions for reconsideration were filed with the WVPSC to explain the financial consequences of the order and seek clarification on certain issues. In February 2026, the WVPSC issued an order upon reconsideration approving a revised ROE of 9.75%. This approved change in ROE results in a revision to the approved annual increase in base rates from $76 million ($67 million related to APCo) to $91 million ($79 million related to APCo) effective February 20, 2026. All other requests for reconsideration were rejected by the WVPSC.

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, NOLCs and AROs.

The WVPSC's August 2025 order on the Companies' West Virginia base case filing, as described in the "2024 West Virginia Base Rate Case" section above, approved the termination of the MRBC and the transition of MRBC rates into base rates. The WVPSC did not rule on MRBC refunds proposed by WVPSC staff and an intervening party related to NOLCs and other issues.

In April 2026, the WVPSC issued an order that adjudicated the Companies' 2024 MRBC surcharge update filing. This order affirms previously approved MRBC revenue requirements and allows the Companies to perform a final true-up in an ENEC filing to recover past MRBC costs that were not reflected in MRBC surcharge rates in a timely manner during the four-year existence of the surcharge. This order also allows the Companies to recognize carrying charges on revised MRBC under-recovery balances starting September 2024 to recover the updated MRBC under-recovery with carrying charges through current ENEC surcharge rates over a period to be determined in the Companies' 2026 ENEC proceeding. The April 2026 order also noted that collection of revenue requirement related to inclusion of a stand-alone NOLC deferred tax asset in MRBC rates may be subject to refund, pending the future issuance of a PLR or other guidance by the IRS.

In May 2026, a group of APCo customers submitted an appeal to the West Virginia Intermediate Court of Appeals alleging that the WVPSC erred in its April 2026 order approving a final MRBC true-up without sufficient record support. This appeal was dismissed by the West Virginia Intermediate Court of Appeals for lack of jurisdiction. The group of APCo customers subsequently submitted the appeal to the West Virginia Supreme Court.

In July 2026, the WVPSC issued an order on the Companies' June 2026 ENEC update filing, approving a $593 million projected August 31, 2026 ENEC under-recovery balance ($274 million related to APCo) that will be included in the Companies' overall balance to be securitized. The WVPSC's order approves the Companies' proposed recovery of the remaining MRBC under-recovery balance of $34 million ($28 million related to APCo) as part of the $593 million ENEC under-recovery balance approved for securitization.

If any refund liabilities are imposed by the WVPSC related to MRBC, it could reduce future net income and cash flows and impact financial condition.

West Virginia Inflation-Based Rate Adjustment

In April 2026, the WVPSC issued an order conditionally approving an annual Inflation-Based Rate Adjustment to current base rates of 4% for residential and commercial customers and 2.5% for industrial customers, provided that the Companies: (a) agree with proceeding with securitization, unless otherwise ordered by the WVPSC, (b) agree that the April 2026 Notice of Intent to file a 2026 West Virginia base rate case will be withdrawn and (c) agree that a new base rate case will not be filed prior to June 1, 2027. In April 2026, the Companies agreed to the terms of the Inflation-Based Rate Adjustment described above and filed revised tariff sheets reflecting a $40 million combined annual increase to base rates effective July 1, 2026.

In May 2026, a group of APCo customers submitted an appeal to the West Virginia Intermediate Court of Appeals alleging that the WVPSC erred in its April 2026 order approving the Inflation-Based Rate Adjustment without adequate findings, evidentiary support or reasoned explanation demonstrating the approval of reasonable rates under WVPSC statutes. This appeal was dismissed by the West Virginia Intermediate Court of Appeals for lack of jurisdiction. The group of APCo customers subsequently submitted the appeal to the West Virginia Supreme Court.

In July 2026, an intervening party submitted an appeal to the West Virginia Supreme Court regarding the Inflation-Based Rate Adjustment alleging that the WVPSC: (a) failed to carry its burden of proving that the Companies' existing rates were unreasonable and needed to be changed, (b) failed to adequately support its order with evidence of record and (c) violated the due process rights of the intervening party and the customers that it represents.

If the Companies are ordered to issue future refunds associated with the Inflation-Based Rate Adjustment, it would reduce future net income and cash flows and impact financial condition.

2025 West Virginia Securitization Filing

In March 2026, the WVPSC issued a final financing order approving the Companies' proposed securitization of the following: (a) remaining combined unrecovered ENEC balances, (b) undepreciated West Virginia jurisdictional plant balances as of December 31, 2022 for the Amos, Mitchell and Mountaineer Plants, (c) undepreciated environmental costs previously approved for recovery through a separate West Virginia surcharge and (d) West Virginia jurisdictional deferred major storm operation and maintenance costs.

In July 2026, the WVPSC issued an order on the June 2026 settlement agreement in the Companies' 2026 ENEC update filing, approving a modified $593 million projected August 31, 2026 ENEC under-recovery balance ($274 million related to APCo) and an overall securitization balance of $2.7 billion ($1.7 billion related to APCo) as reflected in the table below:

Eligible Costs Approved by the WVPSC for Securitization	APCo	WPCo	Total
		(in millions)	
Undepreciated Utility Plant Balances of Amos, Mitchell and Mountaineer (as of December 31, 2022)	$ 1,145	$ 559	$ 1,704
ENEC Under-Recovery Regulatory Assets (a)	274	319	593
Forecasted Undepreciated CCR and ELG Investments of Amos, Mitchell and Mountaineer (as of November 30, 2024) (a)	88	149	237
Deferred Storm Other Operation and Maintenance Expense Regulatory Assets (a)	155	3	158
Upfront Financing Costs (a)	10	6	16
Total	$ 1,672	$ 1,036	$ 2,708

(a) Amounts represent estimates. The WVPSC may update these estimates prior to securitization bond marketing. In December 2025, the KPSC approved KPCo's request for a CPCN to make investments necessary for KPCo to resume: (a) a 50% share of the Mitchell Plant ELG Project and (b) a 50% share of non-ELG capital investments. This approval by the KPSC allows KPCo to continue taking a 50% share of energy and capacity from the Mitchell Plant to serve KPCo customers beyond December 31, 2028. See "Mitchell Plant Filing for Certificate of Public Convenience and Necessity" section below for additional information. In February 2026, WPCo requested that the WVPSC grant any additional authorizations necessary to enable WPCo to reflect the holdings and impact of the December 2025 KPSC order or make a determination that no such authorizations are required. WPCo forecasted CCR and ELG amounts related to the Mitchell Plant are subject to change pending a ruling from the WVPSC on WPCo's February 2026 filing.

In accordance with the West Virginia statutory requirements and the financing order, the issuance of the securitization bonds is subject to final review by the WVPSC after bond pricing. The Companies will proceed with the securitization bond issuance process and plan to complete the securitization in the fourth quarter of 2026, subject to market conditions. 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 May 2026, APCo issued 20-year securitization bonds to finance approximately $1.4 billion of jurisdictional costs, including: (a) $1.2 billion of certain Virginia jurisdictional Property, Plant and Equipment balances for the Amos and Mountaineer Plants, (b) $141 million of Virginia jurisdictional major storm other operation and maintenance expenses deferred to Regulatory Assets during the 2024-2025 biennial period and (c) $11 million of up-front financing costs. After issuing the securitization bonds, APCo implemented a rider to recover annual securitization debt financing costs and the Base Rate Reduction (BRR) Rider to credit customers for the recovery of, and return on, the Amos and Mountaineer Plant costs currently included in APCo Virginia base rates.

2026 Virginia Base Rate Case

In May 2026, APCo filed a request with the Virginia SCC for a net $105 million annual decrease in distribution and generation base rates. Approximately $166 million of the proposed decrease to base rates is currently credited to customers through the BRR Rider associated with the securitization of certain Virginia jurisdictional Amos and Mountaineer Plant balances as described in the "2025 Virginia Securitization Filing" section above, resulting in an estimated net $61 million increase to base rates. The BRR Rider will expire upon the implementation of new base rates. The proposed $61 million annual increase in base rates is based on a 10.5% ROE and an actual capital structure of 50.3% debt and 49.7% common equity. The $61 million requested base rate increase is primarily due to general inflation, increased investment in distribution and generation, increased capital costs, and the costs of required programs to support electric vehicles and low-income solar. Intervenor testimony is due in August 2026 and staff testimony is due in September 2026. A hearing is scheduled for October 2026. The Virginia SCC's final order is required to be issued no later than January 2027 with updated base rates to be implemented in March 2027. If any costs in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

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

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next base rate proceeding. Through June 30, 2026, AEP's share of ETT's cumulative revenues from interim base rate increases that are subject to a prudency review is approximately $2 million. A base rate review could produce a refund to customers if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition.

2026 ETT Base Rate Case

In April 2026, ETT filed a request with the PUCT for a $42 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 10.5% 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 July 2026, following a unanimous settlement in principle among ETT, PUCT Staff and intervenors, the PUCT granted the parties' request to suspend the procedural schedule while the parties document the final settlement agreement. The proposed settlement is subject to approval by the PUCT, and the parties expect to file the agreement in the third quarter of 2026. ETT was granted authority to implement interim rates, subject to refund, effective August 1, 2026. If any of the costs in the case are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

Michigan Power Supply Cost Recovery (PSCR) Reconciliation

2024 PSCR Reconciliation

In March 2025, I&M submitted its 2024 PSCR Reconciliation to the MPSC. In October 2025, 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 $259 thousand to $14 million. In July 2026, the MPSC ordered a $1 million cost disallowance associated with the OVEC ICPA and no cost disallowance associated with the Rockport UPA with AEGCo.

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. If future IURC orders require that I&M provide credits in the FAC factor computation in excess of established earnings test requirements, it could reduce future net income and cash flows and impact financial condition.

In February 2026, I&M submitted its FAC filing and earnings test evaluation for the period ended November 2025. I&M proposed an over-earnings credit to customers for the earnings test period ending November 2025 of $53 million based on requested modifications to jurisdictional cost allocations to more accurately reflect I&M's cost to serve Indiana retail customers. In June 2026, the IURC issued an order approving the jurisdictional cost allocation modifications and the $53 million over-earnings customer credit.

KPCo Rate Matters (Applies to AEP)

Investigation of the Service, Rates and Facilities of KPCo

In June 2023, the KPSC issued an order directing KPCo to show cause why it should not be subject to Kentucky statutory remedies, including fines and penalties, for failure to provide adequate service in its service territory. The KPSC's show cause order did not make any determination regarding the adequacy of KPCo's service. In July 2023, KPCo filed a response to the show cause order demonstrating that it has provided adequate service. In December 2023 and February 2024, KPCo and certain intervenors filed testimony with the KPSC. A hearing with the KPSC was previously scheduled to occur in June 2024. The hearing was postponed and has not yet been rescheduled. If any fines or penalties are levied against KPCo relating to the show cause order, it could reduce future net income and cash flows and impact financial condition.

Mitchell Plant Filing for Certificate of Public Convenience and Necessity

KPCo and WPCo each own a 50% undivided interest in the 1,560 MW coal-fired Mitchell Plant. 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, and pursuant to September 2022 resolutions under the existing Mitchell Plant Operating Agreement, WPCo funded 100% of the Mitchell Plant ELG investments that have been placed in service. In addition, WPCo also paid for a greater than 50% 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 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 requested recovery of an estimated $60 million of Mitchell Plant non-ELG capital investments through its 2025 Kentucky Base Rate Case filing. See "2025 Kentucky Base Rate Case" section below for additional information.

In November 2025, KPCo and an intervening party submitted a settlement agreement that recommended the approval of KPCo's proposed Mitchell Plant CPCN and use of KPCo's Environmental Surcharge to recover Mitchell Plant ELG project costs through 2040. The settlement agreement further recommended granting KPCo authority to defer the depreciation expense and carrying costs associated with Mitchell Plant non-ELG capital investments to a regulatory asset until it can be reflected in rates. The recovery mechanism for Mitchell Plant non-ELG capital investments will be addressed in KPCo's 2025 Kentucky Base Rate Case filing. See "2025 Kentucky Base Rate Case" section below for additional information.

In December 2025, the KPSC issued an order approving the settlement agreement, the Mitchell Plant CPCN and recovery of ELG capital investments through the Environmental Surcharge. The KPSC's order imposes annual reporting requirements to review capital investment costs at the Mitchell Plant.

To operate in accordance with KPSC and WVPSC directives related to Mitchell Plant ELG investments, KPCo and WPCo expect to utilize existing authority under the Mitchell Plant Operating Agreement to revise billing procedures resulting in equal allocation of costs. In February 2026, WPCo requested that the WVPSC grant any additional authorizations necessary to enable WPCo to reflect the holdings and impact of the December 2025 KPSC order or make a determination that no such authorizations are required. As of June 30, 2026, the net book value of KPCo's share of the Mitchell Plant, before cost of removal and including CWIP and inventory, and prior to the effect of revised billing procedures expected under the Mitchell Plant Operating Agreement to comply with the KPSC's December 2025 order, was $520 million.

2025 Kentucky Base Rate Case

In August 2025, KPCo filed a request with the KPSC for a $96 million net annual increase in base rates based upon a proposed 10% ROE and a proposed capital structure of 53.9% debt and 46.1% common equity, to be implemented no earlier than March 2026. Among other changes, the filing proposed a $10 million increase in PJM transmission costs, a $9 million increase due to load loss and a $6 million increase in depreciation rates.

The proposed annual rate increase also included a $20 million annual revenue requirement related to KPCo's investment in the Mitchell Plant. See "Mitchell Plant Filing for Certificate of Public Convenience and Necessity" section above for additional information. As part of this filing, KPCo requested a new generation rider to recover the remaining net book value of KPCo's non-environmental investment in the Mitchell Plant that KPCo historically recovered through base rates. If the generation rider is approved, the $20 million would be removed from the requested revenue requirement increase and would be collected through the rider. Additionally, KPCo is pursuing securitization legislation that would allow KPCo to securitize the remaining net book value of the Mitchell Plant. If the securitization of the remaining Mitchell Plant net book value is successful, collection of costs through the generation rider would cease.

In January 2026, KPCo and certain intervening parties submitted a settlement agreement with the KPSC proposing a $77 million annual increase in Kentucky retail rates, including: (a) a $59 million annual increase in KPCo base rates based on a 9.8% authorized ROE and a capital structure of 53.9% debt and 46.1% common equity, and (b) a new generation rider with a first year revenue requirement of $18 million based on a 9.7% authorized ROE to recover non-environmental plant investments at Mitchell Plant and all incremental capital investments after May 31, 2025 at both Mitchell Plant and Big Sandy Plant. Capital and other operation and maintenance expenses related to any new generating assets also will be eligible for inclusion in the Generation Rider, subject to KPSC approval. The settlement revenue requirement will be reduced by $25 million in the first year and $15 million in the second year through a new rider that returns certain unprotected deferred tax expenses in customer rates on a temporary basis, and then beginning in the third year, collects the deferred tax expense amounts from customers over the estimated time period that taxes are due to the IRS. The settlement agreement also proposes: (a) approval to defer all storm other operation and maintenance expenses above or below the level included in base rates, and (b) approval to defer vegetation management costs above or below the level included in base rates, capped at a total of $45 million in 2026 and $52 million in 2027. Consistent with the KPSC order in KPCo's 2023 Kentucky Base Rate Case filing, the settlement agreement also provides that KPCo's proposal to include a stand-alone NOLC deferred tax asset in rate base will be addressed in a future proceeding upon KPCo's receipt of a PLR or other guidance from the IRS. A hearing was held in January 2026.

In February 2026, the KPSC issued an order modifying the January 2026 settlement agreement and approving an annual increase of $55 million in Kentucky retail rates based upon a 9.75% base rate ROE effective March 1, 2026. This increase is inclusive of a $36 million increase in base rates and a $19 million increase due to the new generation rider. The order reduced the settlement revenue requirement by $22 million primarily due to a $10 million reduction related to FERC transmission expense and a $9 million reduction in incentive and other compensation. Additionally, the KPSC ordered that $47 million of certain vegetation management costs previously incurred and capitalized from January 2018 through May 2025 should be reclassified as a regulatory asset to be recovered over a 30 year period with no carrying costs, and that prospective vegetation management costs incurred should no longer be capitalized but instead be treated as operating expense.

In March 2026, KPCo filed a request with the KPSC seeking rehearing on the vegetation management finding in the base case order in addition to certain other denied costs. In April 2026, the KPSC issued an order approving KPCo's request for rehearing. Additionally, the order authorized KPCo to defer $18 million of certain vegetation management costs previously incurred and capitalized from June 2025 through February 2026 to a regulatory asset, pending the KPSC's final decision on rehearing. In July 2026, KPCo and intervenors filed rehearing briefs. KPCo's filing also requested that the KPSC issue a rehearing order by September 1, 2026. If any costs included in the request for rehearing are not approved for recovery, 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 April 2026 and June 2026, the Supreme Court of Ohio affirmed the PUCO's August 2024 orders finding that costs incurred by OPCo during the 2018-2019 audit period and 2020 audit period, respectively, were prudent.

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. An evidentiary hearing was held in November 2025 and post-hearing briefs were submitted in February 2026. If any costs are disallowed or refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

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.

In January 2026, OPCo, the PUCO staff, and certain intervenors filed a settlement agreement with the PUCO. After incorporating reductions to rider rates, the settlement reflects an annual net revenue increase of $11 million based upon a 9.84% ROE and a capital structure of 49.1% debt and 50.9% common equity while also securing a reduction in customer rates through the amortization of $82 million of deferred tax regulatory liabilities over 18 months, an item not included in the original application. The resulting overall annual revenue impact is a net decrease of $59 million. The difference between OPCo's requested annual base rate increase and the settlement is primarily due to a reduction in the requested ROE. Additionally, the agreement proposed increased revenue caps for the Distribution Investment Rider, annual cost cap increases in the Enhanced Service Reliability Rider and would result in no material disallowances. In April 2026, the PUCO issued an order approving the joint stipulation and settlement agreement and rates went into effect. In May 2026, the PUCO denied applications for rehearing submitted by two intervenors.

March 2026 Storm Costs

In March 2026, the service territory of OPCo was impacted by strong winds from an isolated storm resulting in power outages and damage to the transmission and distribution infrastructure. As of June 30, 2026, OPCo had incurred approximately $25 million in incremental operation and maintenance costs related to service restoration efforts. The incremental storm restoration costs have been deferred as a regulatory asset and OPCo expects to seek future recovery of those costs through its approved storm cost recovery mechanism.

PSO Rate Matters (Applies to AEP and PSO)

2026 Oklahoma Base Rate Case

In January 2026, PSO filed a request with the OCC for a $299 million annual base rate increase based upon a 10.5% ROE with a capital structure of 50.1% debt and 49.9% common equity, net of existing rider revenue and certain incremental renewable facility benefits expected to be provided to customers through riders. PSO also requested an expanded transmission cost recovery rider and a new vegetation management rider. Further, PSO is seeking approval of new large load special terms and conditions in the Large Power and Light tariff.

In May 2026, various intervenors and staff filed testimony supporting an annual base rate increase ranging from $10 million to $109 million based on a recommended ROE ranging from 8.3% to 9.38%. The primary differences between PSO's requested annual increase in base rates and staff and intervenors' recommendations include: (a) a reduction in the proposed ROE, (b) modifications to PSO's previously approved treatment of a stand-alone NOLC deferred tax asset in rate base, (c) treatment of storm costs and (d) adjustments to PSO's proposed depreciation and amortization.

In June 2026, PSO, OCC staff and certain intervening parties filed a non-unanimous partial joint stipulation and settlement agreement for a $73 million revenue increase based upon a 9.375% ROE utilizing PSO's filed actual capital structure of 50.1% debt and 49.9% common equity that includes: (a) a requirement for PSO to provide a credit over a two-year period for deferred tax liabilities related to tax repairs which will then be recovered over the life of the underlying plant after the credit period, (b) PSO to expand its SPP Transmission Cost Rider as requested, (c) no change in the treatment of PSO's NOLC, and (d) PSO to recover vegetation management costs consistent with the amount in PSO's filed request and defer $13 million of eligible vegetation management costs in the first year of implemented rates, and $4 million each year thereafter. All issues related to PSO's proposed large load tariffs would be an open issue at hearing. Certain intervening parties did not sign the settlement agreement and contested certain of its provisions. Interim rates were implemented on July 1, 2026 reflecting the terms of this settlement. A hearing was held and an order is expected in the third quarter of 2026. 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.

SWEPCo Rate Matters (Applies to AEP and SWEPCo)

2025 Texas Base Rate Case

In October 2025, SWEPCo filed a request with the PUCT for a $164 million annual increase in Texas base rates based upon a 10.75% ROE and a proposed capital structure of 48% debt and 52% common equity. The request would move certain revenues recovered through riders, including interim revenues on transmission and distribution investment since the 2020 Texas Base Rate Case, into base rates resulting in a net annual rate increase of $95 million. The proposed net annual increase includes recovery of the Texas jurisdictional share of the retired Pirkey Plant through depreciation expense and requests $21 million annually to recover deferred storm costs and expand the utility's self-insurance reserve for potential losses and damages.

In March 2026, various intervenors filed testimony supporting a reduction to SWEPCo's net request ranging from $36 million to $64 million based on a recommended ROE ranging from 9.25% to 9.44%. In March 2026, PUCT staff filed testimony supporting a reduction to SWEPCo's net request of $26 million based on an ROE of 9.6%. The primary differences between SWEPCo's requested annual increase in base rates and staff and intervenors' recommendations include: (a) recovery of Pirkey Plant, (b) modifications to SWEPCo's previously approved treatment of a stand-alone NOLC deferred tax asset in rate base and (c) a reduction in the proposed ROE.

In April 2026, a unanimous settlement in principle was reached and SWEPCo filed a motion to abate the hearing. A PUCT order on the settlement is expected in the fourth quarter of 2026. If the PUCT does not accept the settlement and 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 measures 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.

FERC Rate Matters

Independence Energy Connection Project (Applies to AEP)

In 2016, PJM approved the Independence Energy Connection Project (IEC) and included it in its Regional Transmission Expansion Plan to alleviate congestion. Transource Energy has an ownership interest in the IEC, which is located in Maryland and Pennsylvania. In June 2020, the Maryland Public Service Commission approved a 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. In September 2025, the United States Court of Appeals for the Third Circuit affirmed the December 2023 district court order in favor of Transource Energy. The Pennsylvania Attorney General subsequently petitioned to intervene, which the United States Court of Appeals for the Third Circuit denied. The Pennsylvania Attorney General sought review of the United States Court of Appeals for the Third Circuit's decision at the United States Supreme Court, which was denied in June 2026.

In May 2026, the Maryland Public Service Commission approved an extension of the construction commencement deadline to June 2027. In May 2026, Transource Energy filed its siting application for a CPCN to provide utility service in Franklin County, Pennsylvania, a petition for exemption from certain local zoning regulations, and a motion to consolidate the three filings.

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 had not been canceled and remained necessary to alleviate congestion. In July 2025, PJM removed the IEC from suspended status and indicated the project going forward will be included in PJM's models with a modified scope. PJM continues to evaluate reliability and market efficiency in the area. As of June 30, 2026, AEP's share of IEC capital expenditures was approximately $97 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	$ 68	$ 61	$ 52	$ 49	$ 308

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 provided refunds for the 2021 rate year, primarily through 2025 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. Requests for rehearing were filed by intervenors in July 2025 and were rejected by the FERC on the merits in November 2025. Intervenors have filed petitions for review of the FERC's orders in this matter with the United States Court of Appeals for the District of Columbia Circuit. The appeals have been consolidated and briefs are expected to be filed by the various parties in the third and fourth quarters of 2026.

As directed by the FERC in its June 2025 order, AEP transmission owning subsidiaries within PJM and SPP submitted compliance filings in August 2025 that revised the 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. In October 2025, intervenors filed comments in response to the compliance filings. In March and April 2026, the FERC approved the AEP transmission owning subsidiaries' compliance filings related to PJM and SPP, respectively.

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	$ 214	$ 6	$ 11	$ —	$ 6	$ 27
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	(24)	—	(17)	—	—	—	—
Other Operation	53	—	15	(6)	—	19	10
Income (Loss) Before Income Tax Expense (Benefit)	241	214	8	17	—	(13)	17
Income Tax Expense (Benefit)	(313)	(203)	(21)	(28)	—	(16)	(39)
Net Income	554	417	29	45	—	3	56
Net Income Attributable to Noncontrolling Interest	55	55	—	—	—	—	—
Earnings Attributable to Common Shareholder	$ 499	$ 362	$ 29	$ 45	$ —	$ 3	$ 56

FERC 2025 PJM Transmission Formula Rate Challenge (Applies to AEP, AEPTCo, APCo, I&M and OPCo)

In March 2026, an intervenor filed a formal challenge and complaint regarding the NOLC adjustments in the 2025 annual update covering the transmission formula rates for 2024 in PJM. In July 2026, the FERC rejected and denied the formal challenge and complaint.

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. In November 2025, the FERC issued an order denying the KPSC and Attorney General of Kentucky complaint. In December 2025, the KPSC and Attorney General of Kentucky requested a rehearing of the November order denying the complaint. In January 2026, the FERC issued a notice of denial of the request for rehearing by operation of law, providing the FERC with additional time to consider and decide on the merits of the request. In February 2026, the KPSC and Attorney General of Kentucky filed a petition for review of the FERC’s orders in this matter with the United States Court of Appeals for the Sixth Circuit and in June 2026, filed their brief. Parties in the matter are expected to file briefs in the third quarter of 2026. In March 2026, the FERC again denied the complaint, continuing to find that the KPSC and Attorney General of Kentucky have not met their burden of proof. 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.

FERC Audit (Applies to all Registrant Subsidiaries)

The FERC Division of Audits and Accounting initiated an audit of SWEPCo in April 2024 evaluating certain accounting and reporting requirements under various FERC regulations, including compliance with the approved terms, rates and conditions of its SPP transmission formula rate mechanism. In March 2026, the FERC issued a final audit report which included, among other things, findings and recommendations related to SWEPCo's policy for the capitalization of certain vegetation management costs.

As a result of the final audit report, beginning in the first quarter of 2026, AEP will no longer capitalize the vegetation management costs identified in the FERC finding on a prospective basis. AEP's PJM and SPP transmission formula rates will provide recovery of these costs as an expense effective with the 2026 rate year. Retail ratemaking for these costs will be determined in current or future ratemaking proceedings in each jurisdiction which may allow the continued capitalization of these costs as property, plant and equipment or deferral as regulatory assets. Management is unable to predict the outcome in any current or future ratemaking proceeding. If any refund liabilities are imposed by any retail commission or any disallowances occur, it would reduce future net income and cash flows and impact financial condition.

Further discussions with the FERC audit staff will be held in the second half of 2026 to finalize the resolution of all findings noted in the final audit report. If any refund liabilities are imposed by the FERC or any disallowances occur, it would reduce future net income and cash flows and impact financial condition for SWEPCo.

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 2025 Annual Report should be read in conjunction with this report.

COMMITMENTS

In June 2026, OPCo completed the transfer of its 4.3% ownership in OVEC to Parent and its 19.93% OVEC power participation entitlement to AGR. Parent remains responsible for the financial and other obligations of AGR under the intercompany power agreement. As a result, OPCo's remaining energy and capacity purchase contract commitments are immaterial.

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.

In April 2026, AEP increased its $5 billion revolving credit facility to $6.5 billion and extended the due date from March 2029 to April 2031. Also, in April 2026, AEP increased its $1 billion revolving credit facility to $1.5 billion and extended the due date from March 2027 to April 2029. 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, 2026, 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 seven uncommitted facilities totaling $850 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of June 30, 2026 were as follows:

Company	Amount (in millions)	Maturity
AEP	$ 535	July 2026 to June 2027

During the second quarter of 2026, AEP issued an additional $131 million of letters of credit under existing uncommitted facilities with maturity dates ranging from April 2027 to June 2027.

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, 2026, 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, 2026, 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	$ 34
AEP Texas	8
APCo	4
I&M	3
OPCo	6
PSO	3
SWEPCo	4

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 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 by May 2028. 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 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, the Federal EPA revisions to the rule, 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.

In January 2026, APCo received a final order from the Virginia SCC approving the recovery of $80 million of Legacy CCR Rule regulatory assets through 2041 and concurrent recovery of ongoing depreciation and accretion expenses. AEP will continue to seek cost recovery through regulated rates in other jurisdictions, 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.

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)

AEP sold the Gavin Power Station to Gavin Power LLC and Lighthouse Generation LLC in 2017. Pursuant to the PSA for that transaction, AEP maintained responsibility to complete closure of the 300 acre unlined fly ash reservoir (FAR) pond in accordance with the closure plan approved by the Ohio Environmental Protection Agency and to indemnify the purchasers for that work. In July 2021, closure work was completed by AEP. In November 2022, the Federal EPA issued a final decision denying Gavin Power LLC's requested extension to allow another pond at the Gavin Power Station, the CCR surface impoundment, 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, including an assertion that the closure of the FAR is noncompliant with the CCR Rule in multiple respects. The owners of the Gavin Power Station have notified AEP that 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 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. The complaint does not assert any claims against AEP. In August 2025, the District Court granted the Federal EPA's Motion to Dismiss the complaint and the Court dismissed the case in December 2025. 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.

Wholesale Generating Contracts (Applies to SWEPCo)

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments engage in generation supply contracts with certain wholesale customers as part of the normal course of business. These contracts have been entered into with various municipalities and cooperatives and are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued-up to actual costs annually.

During the second quarter of 2026, SWEPCo reached agreements with certain existing wholesale customers and is in discussions with one remaining existing wholesale customer under generation supply contracts, which is expected to result in credits to these wholesale customers. While the amount ultimately payable remains subject to resolution of those discussions, SWEPCo recorded a $23 million probable credit within revenues on the statement of income for the period ended June 30, 2026.

6. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

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

ACQUISITIONS

Grover Hill Wind Project (Applies to AEP and APCo)

In May 2026, APCo completed the acquisition of 100% of the equity interests in Grover Hill Wind, LLC, the owner of the Grover Hill wind facility located in Paulding County, Ohio. This facility, placed in service in May 2026, serves both retail and wholesale customers in Virginia and West Virginia. The Virginia and West Virginia jurisdictional shares of the Grover Hill revenue requirement, net of PTC benefits, are recoverable through existing riders until the amounts are reflected in base rates. The acquisition of Grover Hill resulted in the recognition of operating leases for easement and access rights to the land on which the facility is located, as well as the associated ARO. In accordance with the guidance for "Business Combinations," management determined the acquisition represented an asset acquisition. The table below summarizes the impact at acquisition on APCo's balance sheets:

Plant Name	State	Fuel Type	Net Maximum Capacity	Property, Plant and Equipment, Net	Operating Lease Assets	Asset Retirement Obligations
			(MWs)		(in millions)	
Grover Hill	OH	Wind	143	$ 361	$ 8	$ 1

Oregon Clean Energy Center (Applies to AEP and I&M)

In March 2026, I&M completed the acquisition of 100% of the equity interests in Oregon Clean Energy, LLC, the owner of the Oregon Clean Energy Center (Oregon Plant), a natural gas-powered, combined-cycle electric generation facility located in Oregon, Ohio. The Oregon Plant began commercial operations in 2017. I&M acquired the Oregon Plant to provide capacity and energy to both I&M Indiana and FERC jurisdictional customers. As approved by the IURC in November 2025 and prior to incorporation into the development of Indiana base rates, I&M reflects costs associated with the Oregon Plant either as eligible costs for recovery through existing I&M Indiana riders or in I&M's ongoing Indiana earnings test evaluation.

In accordance with the guidance for "Business Combinations," management determined the acquisition of the Oregon Plant represented an asset acquisition. An asset acquisition is 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. The table below summarizes the impact at acquisition on I&M's balance sheets:

Plant Name	Fuel Type	Net Maximum Capacity	Property, Plant and Equipment, Net	Prepayments and Other Current Assets	Materials and Supplies	Accounts Receivable	Accounts Payable
		(MWs)			(in millions)		
Oregon Plant	Natural Gas	870	$ 918	$ 35	$ 5	$ 16	$ 9

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

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 retail and wholesale 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 retail and wholesale 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 ARO. In accordance with the guidance for "Business Combinations," management determined the acquisitions of Pixley and Flat Ridge IV represented 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. Since July 2025, PSO sells a portion of Green Country's capacity to SWEPCo, and this arrangement will continue through May 2027, when the agreement ends. 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 represented 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. 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. 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.

In the first half of 2025, PSO expanded its generation portfolio by acquiring three electric generation facilities for an aggregate purchase price of $1.4 billion. The table below summarizes the impact at acquisition on PSO's balance sheets:

Plant Name	State	Fuel Type	Net Maximum Capacity (MWs)	Property, Plant and Equipment, Net	Operating Lease Assets	Asset Retirement Obligations	Other Liabilities	
					(in millions)			
Pixley	KS	Solar	189	$ 380	$ 9	$ 12	$ —	
Flat Ridge IV	KS	Wind	135	305	7	3	—	
Green Country	OK	Natural Gas	904	819	—	—	91	(a)
Total			1,228	$ 1,504	$ 16	$ 15	$ 91	

(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 Midwest Transmission Holdings (Applies to AEP and AEPTCo)

In January 2025, AEP announced a partnership whereby a nonaffiliated entity would acquire a 19.9% noncontrolling interest in Midwest Transmission Holdings, a subsidiary of AEPTCo Parent that owns all of the issued and outstanding stock of OHTCo and IMTCo. The partnership was structured pursuant to a contribution agreement between AEPTCo, along with Midwest Transmission Holdings, and Olympus BidCo L.P. ("the Investor"), a special purpose entity controlled by (a) investment funds managed by or affiliated with Kohlberg Kravis Roberts & Co. L.P. and (b) Public Sector Pension Investment Board, whereby the Investor agreed to acquire a 19.9% noncontrolling equity interest in Midwest Transmission Holdings for $2.82 billion. The transaction closed in June 2025.

IMPAIRMENTS

2025 Texas Base Rate Case (Applies to AEP and SWEPCo)

During the first quarter of 2026, SWEPCo recorded a pretax disallowance of $31 million in Asset Impairments and Other Related Charges on the statements of income due to a probable, partial regulatory disallowance of recovery of the Pirkey Plant net book value in the 2025 Texas Base Rate Case. See the "2025 Texas Base Rate Case" section of Note 4 for additional information.

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, 2026	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 26	$ 3	$ 3	$ 2	$ 3	$ 1	$ 3
Interest Cost	52	4	6	6	4	2	3
Expected Return on Plan Assets	(63)	(5)	(8)	(8)	(7)	(3)	(3)
Amortization of Net Actuarial Loss	11	1	1	1	1	1	—
Settlements (a)	4	(4)	—	—	—	4	—
Net Periodic Benefit Cost (Credit)	$ 30	$ (1)	$ 2	$ 1	$ 1	$ 5	$ 3

Three Months Ended June 30, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 24	$ 2	$ 2	$ 2	$ 3	$ 2	$ 2
Interest Cost	53	4	7	7	4	2	3
Expected Return on Plan Assets	(71)	(5)	(10)	(10)	(8)	(3)	(3)
Amortization of Net Actuarial Loss	4	1	—	1	1	—	—
Net Periodic Benefit Cost (Credit)	$ 10	$ 2	$ (1)	$ —	$ —	$ 1	$ 2

Six Months Ended June 30, 2026	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 51	$ 5	$ 5	$ 5	$ 5	$ 3	$ 5
Interest Cost	103	8	12	12	9	5	6
Expected Return on Plan Assets	(128)	(10)	(16)	(16)	(13)	(7)	(7)
Amortization of Net Actuarial Loss	21	2	2	2	2	1	1
Settlements (a)	(7)	(8)	—	—	(6)	4	—
Net Periodic Benefit Cost (Credit)	$ 40	$ (3)	$ 3	$ 3	$ (3)	$ 6	$ 5

Six Months Ended June 30, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 48	$ 4	$ 4	$ 5	$ 5	$ 3	$ 4
Interest Cost	106	9	13	13	9	5	6
Expected Return on Plan Assets	(141)	(11)	(19)	(19)	(15)	(7)	(7)
Amortization of Net Actuarial Loss	8	1	1	1	1	—	—
Net Periodic Benefit Cost (Credit)	$ 21	$ 3	$ (1)	$ —	$ —	$ 1	$ 3

(a) Represents deferrals of regulatory activity.

OPEB

Three Months Ended June 30, 2026	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1	$ —	$ —	$ —	$ —	$ —	$ —
Interest Cost	7	—	1	1	1	1	—
Expected Return on Plan Assets	(30)	(2)	(4)	(3)	(2)	(2)	(2)
Amortization of Prior Service Credit	—	—	—	—	—	—	—
Amortization of Net Actuarial Gain	—	—	—	—	—	—	—
Net Periodic Benefit Credit	$ (22)	$ (2)	$ (3)	$ (2)	$ (1)	$ (1)	$ (2)

Three Months Ended June 30, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 1	$ 1	$ —	$ —	$ —	$ —	$ —
Interest Cost	9	—	2	1	1	1	—
Expected Return on Plan Assets	(28)	(2)	(5)	(4)	(3)	(2)	(2)
Amortization of Prior Service Credit	(1)	—	—	—	—	—	—
Net Periodic Benefit Credit	$ (19)	$ (1)	$ (3)	$ (3)	$ (2)	$ (1)	$ (2)

Six Months Ended June 30, 2026	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 2	$ —	$ —	$ —	$ —	$ —	$ —
Interest Cost	15	1	2	2	1	1	1
Expected Return on Plan Assets	(59)	(5)	(8)	(7)	(5)	(3)	(4)
Amortization of Prior Service Credit	(1)	—	—	—	—	—	—
Amortization of Net Actuarial Gain	(1)	—	—	—	—	—	—
Net Periodic Benefit Credit	$ (44)	$ (4)	$ (6)	$ (5)	$ (4)	$ (2)	$ (3)

Six Months Ended June 30, 2025	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Service Cost	$ 2	$ 1	$ —	$ —	$ —	$ —	$ —
Interest Cost	17	1	3	2	2	1	1
Expected Return on Plan Assets	(56)	(5)	(9)	(7)	(6)	(3)	(4)
Amortization of Prior Service Credit	(1)	—	—	—	—	—	—
Amortization of Net Actuarial Loss	(1)	—	—	—	—	—	—
Net Periodic Benefit Credit	$ (39)	$ (3)	$ (6)	$ (5)	$ (4)	$ (2)	$ (3)

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	$ 95
AEP Texas	12
APCo	—
I&M	2
PSO	1
SWEPCo	9

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.

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.

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 tables below represent AEP's reportable segment income statement information for the three and six months ended June 30, 2026 and 2025 and reportable segment balance sheet information as of June 30, 2026 and December 31, 2025. The significant expenses disclosed below align with the segment-level information that is regularly provided to the CODM.

	Three Months Ended June 30, 2026								
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments		Consolidated
					(in millions)				
Revenues from:									
External Customers	$ 3,050	$ 1,568	$ 129	$ 693	$ 5,440	$ 5	$ —		$ 5,445
Other Operating Segments	70	15	481	16	582	25	(607)	(b)	—
Total Revenues	3,120	1,583	610	709	6,022	30	(607)		5,445
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	900	187	—	588	1,675	—	(72)		1,603
Other Operation and Maintenance	1,055	655	57	6	1,773	27	(542)		1,258
Depreciation and Amortization	569	210	130	5	914	(4)	—		910
Taxes Other Than Income Taxes	143	190	87	—	420	—	7		427
Allowance for Equity Funds Used During Construction	21	28	26	—	75	—	—		75
Interest Expense	264	117	68	2	451	170	(36)		585
Income Tax Expense (Benefit)	(64)	37	63	29	65	(13)	—		52
Equity Earnings of Unconsolidated Subsidiaries	1	—	24	—	25	4	—		29
Other Segment Items (c)	(9)	(7)	30	(18)	(4)	(31)	36		1
Earnings (Loss) Attributable to AEP Common Shareholders	$ 284	$ 222	$ 225	$ 97	$ 828	$ (115)	$ —		$ 713
Gross Property Additions	$ 1,465	$ 1,004	$ 471	$ 74	$ 3,014	$ 136	$ (24)		$ 3,126

	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	$ 1,443	$ 155	$ 552	$ 5,084	$ 3	$ —		$ 5,087
Other Operating Segments	81	6	602	14	703	27	(730)	(b)	—
Total Revenues	3,015	1,449	757	566	5,787	30	(730)		5,087
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	921	203	—	493	1,617	—	(76)		1,541
Other Operation and Maintenance	981	541	46	—	1,568	20	(660)		928
Depreciation and Amortization	532	201	121	5	859	(5)	—		854
Taxes Other Than Income Taxes	122	159	78	—	359	—	6		365
Allowance for Equity Funds Used During Construction	16	19	22	—	57	—	—		57
Interest Expense	202	99	59	2	362	151	(24)		489
Income Tax Expense (Benefit)	(137)	51	(139)	18	(207)	(44)	—		(251)
Equity Earnings (Loss) of Unconsolidated Subsidiaries	1	—	22	—	23	(2)	—		21
Other Segment Items (c)	(22)	(10)	58	(14)	12	(23)	24		13
Earnings (Loss) Attributable to AEP Common Shareholders	$ 433	$ 224	$ 578	$ 62	$ 1,297	$ (71)	$ —		$ 1,226
Gross Property Additions	$ 2,232	$ 664	$ 384	$ 3	$ 3,283	$ 6	$ (10)		$ 3,279

	Six Months Ended June 30, 2026								
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)								
Revenues from:									
External Customers	$ 6,415	$ 3,162	$ 256	$ 1,624	$ 11,457	$ 8	$ —		$ 11,465
Other Operating Segments	145	30	952	37	1,164	53	(1,217)	(b)	—
Total Revenues	6,560	3,192	1,208	1,661	12,621	61	(1,217)		11,465
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,975	458	—	1,442	3,875	—	(154)		3,721
Other Operation and Maintenance	2,072	1,235	110	15	3,432	65	(1,078)		2,419
Asset Impairments and Other Related Charges	31	—	—	—	31	—	—		31
Depreciation and Amortization	1,128	427	261	10	1,826	(9)	—		1,817
Taxes Other Than Income Taxes	287	390	177	1	855	—	15		870
Allowance for Equity Funds Used During Construction	44	53	48	—	145	—	—		145
Interest Expense	509	222	137	3	871	336	(70)		1,137
Income Tax Expense (Benefit)	(112)	77	130	51	146	(50)	—		96
Equity Earnings of Unconsolidated Subsidiaries	1	—	49	—	50	4	—		54
Other Segment Items (c)	(31)	(23)	56	(33)	(31)	(53)	70		(14)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 746	$ 459	$ 434	$ 172	$ 1,811	$ (224)	$ —		$ 1,587
Gross Property Additions	$ 3,608	$ 2,065	$ 904	$ 79	$ 6,656	$ 283	$ (18)		$ 6,921

	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	$ 2,958	$ 271	$ 1,282	$ 10,531	$ 19	$ —		$ 10,550
Other Operating Segments	133	18	1,028	31	1,210	55	(1,265)	(b)	—
Total Revenues	6,153	2,976	1,299	1,313	11,741	74	(1,265)		10,550
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1,996	466	—	1,076	3,538	—	(144)		3,394
Other Operation and Maintenance	1,865	1,118	83	30	3,096	36	(1,133)		1,999
Depreciation and Amortization	1,047	404	237	9	1,697	(10)	—		1,687
Taxes Other Than Income Taxes	256	364	153	1	774	1	12		787
Allowance for Equity Funds Used During Construction	32	38	44	—	114	—	—		114
Interest Expense	402	211	116	4	733	298	(47)		984
Income Tax Expense (Benefit)	(92)	85	(72)	54	(25)	(101)	—		(126)
Equity Earnings of Unconsolidated Subsidiaries	1	1	46	—	48	11	—		59
Other Segment Items (c)	(45)	(22)	59	(25)	(33)	(42)	47		(28)
Earnings (Loss) Attributable to AEP Common Shareholders	$ 757	$ 389	$ 813	$ 164	$ 2,123	$ (97)	$ —		$ 2,026
Gross Property Additions	$ 3,153	$ 1,368	$ 814	$ 7	$ 5,342	$ 36	$ 1		$ 5,379

	June 30, 2026							
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Total Assets	$ 65,606	$ 30,878	$ 20,832	$ 2,938	$ 120,254	$ 7,092 (d)	$ (5,776) (e)	$ 121,570
Investments in Equity Method Investees	$ 9	$ 2	$ 1,091	$ —	$ 1,102	$ 230	$ —	$ 1,332

	December 31, 2025							
	VIU	T&D	AEPTHCo	G&M	Total Reportable Segments	Corporate and Other (a)	Reconciling Adjustments	Consolidated
					(in millions)			
Total Assets	$ 61,778	$ 29,272	$ 19,719	$ 2,003	$ 112,772	$ 6,733 (d)	$ (5,045) (e)	$ 114,460
Investments in Equity Method Investees	$ 9	$ 4	$ 1,068	$ —	$ 1,081	$ 171	$ —	$ 1,252

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, income tax expense and other nonallocated costs.
(b) Represents inter-segment revenues.
(c) 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 Periodic 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 earnings (loss) attributable to common shareholders and 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. Earnings (loss) attributable to common shareholders and net income (loss) include 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, 2026 and 2025 and reportable segment balance sheet information as of June 30, 2026 and December 31, 2025. The significant expenses disclosed below align with the segment-level information that is regularly provided to the CODM.

	Three Months Ended June 30, 2026			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 107	$ —	$ —	$ 107
Sales to AEP Affiliates	474	—	—	474
Other Revenues	7	—	—	7
Total Revenues	588	—	—	588
Other Operation and Maintenance	53	—	—	53
Depreciation and Amortization	128	—	—	128
Taxes Other Than Income Taxes	86	—	—	86
Interest Income	—	73	(71) (a)	2
Allowance for Equity Funds Used During Construction	26	—	—	26
Interest Expense	63	72	(71) (a)	64
Income Tax Expense	62	—	—	62
Other Segment Items (b)	—	31	—	31
Earnings (Loss) Attributable to AEPTCo Common Shareholders	$ 222	$ (30) (c)	$ —	$ 192
Gross Property Additions	$ 462	$ —	$ —	$ 462

	Three Months Ended June 30, 2025			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 145	$ —	$ —	$ 145
Sales to AEP Affiliates	597	—	—	597
Total Revenues	742	—	—	742
Other Operation and Maintenance	42	—	—	42
Depreciation and Amortization	119	—	—	119
Taxes Other Than Income Taxes	76	—	—	76
Interest Income	1	84	(83) (a)	2
Allowance for Equity Funds Used During Construction	21	—	—	21
Interest Expense	77	63	(83) (a)	57
Income Tax Expense (Benefit)	(156)	10	—	(146)
Other Segment Items (b)	—	61	—	61
Earnings (Loss) Attributable to AEPTCo Common Shareholders	$ 606	$ (50) (c)	$ —	$ 556
Gross Property Additions	$ 365	$ —	$ —	$ 365

	Six Months Ended June 30, 2026			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 217	$ —	$ —	$ 217
Sales to AEP Affiliates	942	—	—	942
Other Revenues	7	—	—	7
Total Revenues	1,166	—	—	1,166
Other Operation and Maintenance	104	—	—	104
Depreciation and Amortization	256	—	—	256
Taxes Other Than Income Taxes	174	—	—	174
Interest Income	1	146	(143) (a)	4
Allowance for Equity Funds Used During Construction	48	—	—	48
Interest Expense	128	144	(143) (a)	129
Income Tax Expense	122	—	—	122
Other Segment Items (b)	—	58	—	58
Earnings (Loss) Attributable to AEPTCo Common Shareholders	$ 431	$ (56) (c)	$ —	$ 375
Gross Property Additions	$ 865	$ —	$ —	$ 865

	Six Months Ended June 30, 2025			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 249	$ —	$ —	$ 249
Sales to AEP Affiliates	1,020	—	—	1,020
Total Revenues	1,269	—	—	1,269
Other Operation and Maintenance	76	—	—	76
Depreciation and Amortization	233	—	—	233
Taxes Other Than Income Taxes	150	—	—	150
Interest Income	1	173	(172) (a)	2
Allowance for Equity Funds Used During Construction	43	—	—	43
Interest Expense	161	123	(172) (a)	112
Income Tax Expense (Benefit)	(95)	10	—	(85)
Other Segment Items (b)	—	61	—	61
Earnings (Loss) Attributable to AEPTCo Common Shareholders	$ 788	$ (21) (c)	$ —	$ 767
Gross Property Additions	$ 787	$ —	$ —	$ 787

	June 30, 2026			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets	$ 19,024	$ 7,252 (d)	$ (7,200) (e)	$ 19,076

	December 31, 2025			
	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Total Assets	$ 17,983	$ 6,766 (d)	$ (6,750) (e)	$ 17,999

(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 Board of Directors of AEP.

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

Notional Volume of Derivative Instruments

	June 30, 2026							December 31, 2025						
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)	371	—	44	23	2	6	6	327	—	23	8	2	8	6
Natural Gas (MMBtus)	181	—	46	—	—	53	24	166	—	48	—	—	44	26
Heating Oil and Gasoline (Gallons)	7	1	1	2	1	1	1	8	2	1	2	1	1	1
Interest Rate (USD)	$ 46	$ —	$ —	$ —	$ —	$ —	$ —	$ 40	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate on Long-term Debt (USD)	$ 500	$ —	$ —	$ —	$ —	$ —	$ —	$ 500	$ —	$ —	$ —	$ —	$ —	$ —

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 risks.

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 $105 million and $83 million as of June 30, 2026 and December 31, 2025, respectively. The amount of cash collateral received from third-parties netted against short-term and long-term risk management assets was not material for the Registrant Subsidiaries as of June 30, 2026. 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 December 31, 2025. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was not material for the Registrants as of June 30, 2026 and December 31, 2025.

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, 2026						
	AEP	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
Assets:				(in millions)			
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 1,296	$ 1	$ 175	$ 58	$ 1	$ 44	$ 43
Hedging Contracts - Commodity	78	—	—	—	—	—	—
Total Current Risk Management Assets	1,374	1	175	58	1	44	43
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	568	—	—	2	—	—	—
Hedging Contracts - Commodity	57	—	—	—	—	—	—
Total Long-term Risk Management Assets	625	—	—	2	—	—	—
Total Assets	$ 1,999	$ 1	$ 175	$ 60	$ 1	$ 44	$ 43
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 914	$ —	$ 14	$ 41	$ 4	$ 23	$ 10
Hedging Contracts - Commodity	15	—	—	—	—	—	—
Hedging Contracts - Interest Rate	17	—	—	—	—	—	—
Total Current Risk Management Liabilities	946	—	14	41	4	23	10
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	489	—	2	3	24	6	3
Hedging Contracts - Commodity	13	—	—	—	—	—	—
Hedging Contracts - Interest Rate	10	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	512	—	2	3	24	6	3
Total Liabilities	$ 1,458	$ —	$ 16	$ 44	$ 28	$ 29	$ 13
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 541	$ 1	$ 159	$ 16	$ (27)	$ 15	$ 30

	December 31, 2025						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:				(in millions)			
Current Risk Management Assets							
Risk Management Contracts - Commodity	$ 720	$ —	$ 82	$ 23	$ —	$ 44	$ 37
Hedging Contracts - Commodity	56	—	—	—	—	—	—
Total Current Risk Management Assets	776	—	82	23	—	44	37
Long-term Risk Management Assets							
Risk Management Contracts - Commodity	518	—	2	1	—	—	—
Hedging Contracts - Commodity	63	—	—	—	—	—	—
Total Long-term Risk Management Assets	581	—	2	1	—	—	—
Total Assets	$ 1,357	$ —	$ 84	$ 24	$ —	$ 44	$ 37
Liabilities:							
Current Risk Management Liabilities							
Risk Management Contracts - Commodity	$ 500	$ —	$ 5	$ 13	$ 5	$ 29	$ 11
Hedging Contracts - Commodity	16	—	—	—	—	—	—
Hedging Contracts - Interest Rate	16	—	—	—	—	—	—
Total Current Risk Management Liabilities	532	—	5	13	5	29	11
Long-term Risk Management Liabilities							
Risk Management Contracts - Commodity	420	—	1	1	28	1	2
Hedging Contracts - Commodity	5	—	—	—	—	—	—
Hedging Contracts - Interest Rate	13	—	—	—	—	—	—
Total Long-term Risk Management Liabilities	438	—	1	1	28	1	2
Total Liabilities	$ 970	$ —	$ 6	$ 14	$ 33	$ 30	$ 13
Total MTM Derivative Contract Net Assets (Liabilities) Recognized	$ 387	$ —	$ 78	$ 10	$ (33)	$ 14	$ 24

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, 2026						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:				(in millions)			
Current Risk Management Assets							
Gross Amounts Recognized	$ 1,374	$ 1	$ 175	$ 58	$ 1	$ 44	$ 43
Gross Amounts Offset	(841)	(1)	(4)	(36)	(1)	(1)	(1)
Net Amounts Presented	533	—	171	22	—	43	42
Long-term Risk Management Assets							
Gross Amounts Recognized	625	—	—	2	—	—	—
Gross Amounts Offset	(390)	—	—	(2)	—	—	—
Net Amounts Presented	235	—	—	—	—	—	—
Total Assets	$ 768	$ —	$ 171	$ 22	$ —	$ 43	$ 42
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 946	$ —	$ 14	$ 41	$ 4	$ 23	$ 10
Gross Amounts Offset	(794)	—	(4)	(41)	—	(1)	—
Net Amounts Presented	152	—	10	—	4	22	10
Long-term Risk Management Liabilities							
Gross Amounts Recognized	512	—	2	3	24	6	3
Gross Amounts Offset	(337)	—	—	(3)	—	—	—
Net Amounts Presented	175	—	2	—	24	6	3
Total Liabilities	$ 327	$ —	$ 12	$ —	$ 28	$ 28	$ 13
Total MTM Derivative Contract Net Assets (Liabilities)	$ 441	$ —	$ 159	$ 22	$ (28)	$ 15	$ 29

	December 31, 2025						
	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
Assets:				(in millions)			
Current Risk Management Assets							
Gross Amounts Recognized	$ 776	$ —	$ 82	$ 23	$ —	$ 44	$ 37
Gross Amounts Offset	(424)	—	(1)	(13)	—	(2)	(2)
Net Amounts Presented	352	—	81	10	—	42	35
Long-term Risk Management Assets							
Gross Amounts Recognized	581	—	2	1	—	—	—
Gross Amounts Offset	(316)	—	(1)	(1)	—	—	—
Net Amounts Presented	265	—	1	—	—	—	—
Total Assets	$ 617	$ —	$ 82	$ 10	$ —	$ 42	$ 35
Liabilities:							
Current Risk Management Liabilities							
Gross Amounts Recognized	$ 532	$ —	$ 5	$ 13	$ 5	$ 29	$ 11
Gross Amounts Offset	(400)	—	(2)	(13)	—	(2)	(2)
Net Amounts Presented	132	—	3	—	5	27	9
Long-term Risk Management Liabilities							
Gross Amounts Recognized	438	—	1	1	28	1	2
Gross Amounts Offset	(260)	—	(1)	(1)	—	—	—
Net Amounts Presented	178	—	—	—	28	1	2
Total Liabilities	$ 310	$ —	$ 3	$ —	$ 33	$ 28	$ 11
Total MTM Derivative Contract Net Assets (Liabilities)	$ 307	$ —	$ 79	$ 10	$ (33)	$ 14	$ 24

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, 2026						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ 1	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	11	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	1	1	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	4	—	4	—	—	—	—
Other Operation	2	—	—	—	—	—	—
Maintenance	2	1	1	—	1	—	—
Regulatory Assets (a)	8	—	3	—	3	4	(1)
Regulatory Liabilities (a)	167	(1)	55	7	—	39	46
Total Gain on Risk Management Contracts	$ 195	$ —	$ 64	$ 8	$ 4	$ 43	$ 45

	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	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	(13)	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	—	12	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	1	—	1	—	—	—	—
Regulatory Assets (a)	(6)	—	—	(1)	3	(6)	(3)
Regulatory Liabilities (a)	77	—	3	4	3	29	41
Total Gain on Risk Management Contracts	$ 71	$ —	$ 4	$ 15	$ 6	$ 23	$ 38

	Six Months Ended June 30, 2026						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ (29)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	110	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	1	(30)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	13	—	13	—	—	—	—
Other Operation	2	—	—	—	—	—	—
Maintenance	2	1	1	—	1	—	—
Regulatory Assets (a)	2	—	—	—	5	1	(4)
Regulatory Liabilities (a)	348	1	158	14	3	74	56
Total Gain (Loss) on Risk Management Contracts	$ 448	$ 2	$ 173	$ (16)	$ 9	$ 75	$ 52

	Six Months Ended June 30, 2025						
Location of Gain (Loss)	**AEP**	**AEP Texas**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)			
Vertically Integrated Utilities Revenues	$ (20)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	60	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	—	(21)	—	—	—
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	4	—	4	—	—	—	—
Regulatory Assets (a)	(5)	—	—	(1)	—	(2)	(2)
Regulatory Liabilities (a)	230	—	60	15	6	67	71
Total Gain (Loss) on Risk Management Contracts	$ 269	$ —	$ 64	$ (7)	$ 6	$ 65	$ 69

(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, 2026	December 31, 2025	June 30, 2026	December 31, 2025
	(in millions)			
Long-term Debt (a) (b)	$ (483)	$ (484)	$ 16	$ 15

(a) Amounts included within Long-term Debt on the balance sheet.
(b) Amounts include $(11) million and $(14) million as of June 30, 2026 and December 31, 2025, 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,	
	2026	2025	2026	2025
	(in millions)			
Gain (Loss) on Interest Rate Contracts:				
Fair Value Hedging Instruments (a)	$ 6	$ 21	$ 3	$ 24
Fair Value Portion of Long-term Debt (a)	(6)	(21)	(3)	(24)

(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, 2026 and 2025, 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, 2026 and 2025, the Registrants did not apply cash flow hedging to outstanding interest rate derivatives.

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, 2026				December 31, 2025			
	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	$ 85	$ (1)	$ 50	$ —	$ 78	$ (1)	$ 31	$ —
AEP Texas	—	6	—	1	—	6	—	1
APCo	—	4	—	1	—	4	—	1
I&M	—	(5)	—	—	—	(5)	—	—
PSO	—	2	—	—	—	2	—	—
SWEPCo	—	1	—	—	—	1	—	—

As of June 30, 2026, the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is approximately 9 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, 2026 and December 31, 2025. The Registrant Subsidiaries had no derivative contracts with collateral triggering events in a net liability position as of June 30, 2026 and December 31, 2025.

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 $27 million and $30 million and no cash collateral posted as of June 30, 2026 and December 31, 2025, 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 as of June 30, 2026 and December 31, 2025.

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 $179 million and $183 million and no cash collateral posted as of June 30, 2026 and December 31, 2025, respectively, after considering contractual netting arrangements. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $12 million, $28 million and $13 million, respectively, and no cash collateral posted as of June 30, 2026. APCo, PSO and SWEPCo had derivative contracts with cross-default provisions in a net liability position of $2 million, $27 million and $10 million, respectively, and no cash collateral posted as of December 31, 2025. If a cross-default provision would have been triggered, settlement at fair value would have been required. The other Registrant Subsidiaries had immaterial derivative contracts with cross-default provisions in a net liability position as of June 30, 2026 and December 31, 2025.

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 Measurement" 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, 2026		December 31, 2025	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in millions)			
AEP	$ 50,808	$ 48,075	$ 47,322	$ 44,930
AEP Texas	7,696	7,199	7,016	6,586
AEPTCo	6,756	5,923	6,599	5,812
APCo	7,435	7,290	6,259	6,147
I&M	4,146	3,836	3,561	3,288
OPCo	3,720	3,320	3,718	3,331
PSO	3,527	3,326	3,526	3,349
SWEPCo	4,858	4,461	4,974	4,603

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, 2026			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash (a)	$ 72	$ —	$ —	$ 72
Other Cash Deposits	10	—	—	10
Fixed Income Securities – Mutual Funds (b)	176	—	(3)	173
Equity Securities – Mutual Funds	13	32	—	45
Total Other Temporary Investments and Restricted Cash	$ 271	$ 32	$ (3)	$ 300

	December 31, 2025			
Other Temporary Investments and Restricted Cash	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash (a)	$ 71	$ —	$ —	$ 71
Other Cash Deposits	13	—	—	13
Fixed Income Securities – Mutual Funds (b)	167	—	(2)	165
Equity Securities – Mutual Funds	13	29	—	42
Total Other Temporary Investments and Restricted Cash	$ 264	$ 29	$ (2)	$ 291

(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, 2026	Three Months Ended June 30, 2025	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
	(in millions)			
Proceeds from Investment Sales	$ —	$ 7	$ 7	$ 17
Purchases of Investments	13	5	15	7
Gross Realized Gains on Investment Sales	—	—	1	4
Gross Realized Losses on Investment Sales	—	1	—	1

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, 2026				December 31, 2025			
	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	$ 22	$ —	$ —	$ —	$ 29	$ —	$ —	$ —
Fixed Income Securities:								
United States Government	1,322	8	(3)	(17)	1,351	22	(1)	(15)
Corporate Debt	412	3	(10)	(6)	376	6	(7)	(6)
Subtotal Fixed Income Securities	1,734	11	(13)	(23)	1,727	28	(8)	(21)
Equity Securities - Domestic	3,485	2,928	(2)	—	3,160	2,621	(1)	—
Spent Nuclear Fuel and Decommissioning Trusts	$ 5,241	$ 2,939	$ (15)	$ (23)	$ 4,916	$ 2,649	$ (9)	$ (21)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2026	2025	2026	2025
	(in millions)			
Proceeds from Investment Sales	$ 661	$ 717	$ 1,209	$ 1,294
Purchases of Investments	676	729	1,249	1,330
Gross Realized Gains on Investment Sales	3	2	8	4
Gross Realized Losses on Investment Sales	3	2	7	3

The base cost of fixed income securities was $1.8 billion and $1.7 billion as of June 30, 2026 and December 31, 2025, respectively. The base cost of equity securities was $560 million and $540 million as of June 30, 2026 and December 31, 2025, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of June 30, 2026 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 450
After 1 year through 5 years	608
After 5 years through 10 years	297
After 10 years	379
Total	$ 1,734

Fair Value Measurements of Financial Assets and Liabilities

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

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2026

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 52	$ —	$ —	$ 20	$ 72
Other Cash Deposits (a)	—	—	—	10	10
Fixed Income Securities – Mutual Funds	173	—	—	—	173
Equity Securities – Mutual Funds (b)	45	—	—	—	45
Total Other Temporary Investments and Restricted Cash	270	—	—	30	300
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	5	1,297	537	(1,186)	653
Cash Flow Hedges:					
Commodity Hedges (c)	—	117	18	(20)	115
Total Risk Management Assets	5	1,414	555	(1,206)	768
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	8	—	—	14	22
Fixed Income Securities:					
United States Government	—	1,322	—	—	1,322
Corporate Debt	—	412	—	—	412
Subtotal Fixed Income Securities	—	1,734	—	—	1,734
Equity Securities – Domestic (b)	3,485	—	—	—	3,485
Total Spent Nuclear Fuel and Decommissioning Trusts	3,493	1,734	—	14	5,241
Total Assets	$ 3,768	$ 3,148	$ 555	$ (1,162)	$ 6,309
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 4	$ 1,201	$ 174	$ (1,087)	$ 292
Cash Flow Hedges:					
Commodity Hedges (c)	—	28	1	(21)	8
Fair Value Hedges	—	27	—	—	27
Total Risk Management Liabilities	$ 4	$ 1,256	$ 175	$ (1,108)	$ 327

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2025

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments and Restricted Cash					
Restricted Cash	$ 48	$ —	$ —	$ 23	$ 71
Other Cash Deposits (a)	—	—	—	13	13
Fixed Income Securities – Mutual Funds	165	—	—	—	165
Equity Securities – Mutual Funds (b)	42	—	—	—	42
Total Other Temporary Investments and Restricted Cash	255	—	—	36	291
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	2	831	393	(713)	513
Cash Flow Hedges:					
Commodity Hedges (c)	—	100	18	(14)	104
Total Risk Management Assets	2	931	411	(727)	617
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14	—	—	15	29
Fixed Income Securities:					
United States Government	—	1,351	—	—	1,351
Corporate Debt	—	376	—	—	376
Subtotal Fixed Income Securities	—	1,727	—	—	1,727
Equity Securities – Domestic (b)	3,160	—	—	—	3,160
Total Spent Nuclear Fuel and Decommissioning Trusts	3,174	1,727	—	15	4,916
Total Assets	$ 3,431	$ 2,658	$ 411	$ (676)	$ 5,824
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 4	$ 752	$ 151	$ (633)	$ 274
Cash Flow Hedges:					
Commodity Hedges (c)	—	19	1	(14)	6
Fair Value Hedges	—	30	—	—	30
Total Risk Management Liabilities	$ 4	$ 801	$ 152	$ (647)	$ 310

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2026

Assets:	**Level 1**	**Level 2**	**Level 3** (in millions)	**Other**	**Total**
Restricted Cash for Securitized Funding	$ 13	$ —	$ —	$ —	$ 13
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	1	—	(1)	—
Total Assets	$ 13	$ 1	$ —	$ (1)	$ 13

December 31, 2025

Assets:	**Level 1**	**Level 2**	**Level 3** (in millions)	**Other**	**Total**
Restricted Cash for Securitized Funding	$ 14	$ —	$ —	$ —	$ 14

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2026

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 25	$ —	$ —	$ —	$ 25
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	2	173	(4)	171
Total Assets	$ 25	$ 2	$ 173	$ (4)	$ 196
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 14	$ 2	$ (4)	$ 12

December 31, 2025

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 18	$ —	$ —	$ —	$ 18
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	3	81	(2)	82
Total Assets	$ 18	$ 3	$ 81	$ (2)	$ 100
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 6	$ —	$ (3)	$ 3

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2026

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 26	$ 26	$ (30)	$ 22
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	8	—	—	14	22
Fixed Income Securities:					
United States Government	—	1,322	—	—	1,322
Corporate Debt	—	412	—	—	412
Subtotal Fixed Income Securities	—	1,734	—	—	1,734
Equity Securities - Domestic (b)	3,485	—	—	—	3,485
Total Spent Nuclear Fuel and Decommissioning Trusts	3,493	1,734	—	14	5,241
Total Assets	$ 3,493	$ 1,760	$ 26	$ (16)	$ 5,263
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 31	$ 4	$ (35)	$ —

December 31, 2025

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 12	$ 9	$ (11)	$ 10
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	14	—	—	15	29
Fixed Income Securities:					
United States Government	—	1,351	—	—	1,351
Corporate Debt	—	376	—	—	376
Subtotal Fixed Income Securities	—	1,727	—	—	1,727
Equity Securities - Domestic (b)	3,160	—	—	—	3,160
Total Spent Nuclear Fuel and Decommissioning Trusts	3,174	1,727	—	15	4,916
Total Assets	$ 3,174	$ 1,739	$ 9	$ 4	$ 4,926
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 11	$ —	$ (11)	$ —

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2026

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 1	$ —	$ (1)	$ —
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 28	$ —	$ 28

December 31, 2025

	Level 1	Level 2	Level 3	Other	Total
Liabilities:			(in millions)		
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ —	$ 33	$ —	$ 33

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2026

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 1	$ 43	$ (1)	$ 43
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 29	$ —	$ (1)	$ 28

December 31, 2025

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c)	$ —	$ 1	$ 43	$ (2)	$ 42
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 28	$ 2	$ (2)	$ 28

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2026

	Level 1		Level 2		Level 3		Other		Total	
Assets:					(in millions)					
Restricted Cash for Securitized Funding	$	14	$	—	$	—	$	—	$	14
Risk Management Assets										
Risk Management Commodity Contracts (c)		—		1		42		(1)		42
Total Assets	$	14	$	1	$	42	$	(1)	$	56
Liabilities:										
Risk Management Liabilities										
Risk Management Commodity Contracts (c)	$	—	$	13	$	—	$	—	$	13

December 31, 2025

	Level 1		Level 2		Level 3		Other		Total	
Assets:					(in millions)					
Restricted Cash for Securitized Funding	$	15	$	—	$	—	$	—	$	15
Risk Management Assets										
Risk Management Commodity Contracts (c)		—		—		37		(2)		35
Total Assets	$	15	$	—	$	37	$	(2)	$	50
Liabilities:										
Risk Management Liabilities										
Risk Management Commodity Contracts (c)	$	—	$	11	$	2	$	(2)	$	11

(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, 2026 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 2026 and $2 million in periods 2027-2029; Level 2 matures $20 million in 2026, $76 million in periods 2027-2029 and $1 million in periods 2030-2031; Level 3 matures $156 million in 2026, $224 million in periods 2027-2029, $(3) million in periods 2030-2031 and $(14) million in periods 2032-2035. 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, 2025 maturities of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), were as follows: Level 1 matures $(2) million in 2026; Level 2 matures $12 million in 2026, $65 million in periods 2027-2029, and $1 million in periods 2030-2031; Level 3 matures $210 million in 2026, $51 million in periods 2027-2029, $(6) million in periods 2030-2031 and $(13) million in periods 2032-2034. 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, 2026	**AEP**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in millions)			
Balance as of March 31, 2026	$ 132	$ 21	$ 2	$ (32)	$ 21	$ 15
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	86	50	6	—	8	9
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(7)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	2	—	—	—	—	—
Settlements	(157)	(71)	(8)	2	(29)	(24)
Transfers into Level 3 (d) (e)	1	—	—	—	—	—
Transfers out of Level 3 (e)	(2)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	325	171	22	2	43	42
Balance as of June 30, 2026	$ 380	$ 171	$ 22	$ (28)	$ 43	$ 42

Three Months Ended June 30, 2025	**AEP**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
			(in millions)			
Balance as of March 31, 2025	$ 123	$ 8	$ 4	$ (51)	$ 15	$ 13
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	53	10	3	—	18	19
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(3)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	(1)	—	—	—	—	—
Settlements	(101)	(18)	(7)	2	(33)	(32)
Transfers into Level 3 (d) (e)	5	—	—	—	—	—
Transfers out of Level 3 (e)	(2)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	309	108	12	1	97	69
Balance as of June 30, 2025	$ 383	$ 108	$ 12	$ (48)	$ 97	$ 69

Six Months Ended June 30, 2026	AEP	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)		
Balance as of December 31, 2025	$ 259	$ 81	$ 9	$ (33)	$ 41	$ 35
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	265	162	12	1	47	18
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	(8)	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	10	—	—	—	—	—
Settlements	(473)	(243)	(20)	2	(88)	(52)
Transfers into Level 3 (d) (e)	2	—	—	—	—	—
Transfers out of Level 3 (e)	(1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	326	171	21	2	43	41
Balance as of June 30, 2026	$ 380	$ 171	$ 22	$ (28)	$ 43	$ 42

Six Months Ended June 30, 2025	AEP	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)		
Balance as of December 31, 2024	$ 166	$ 35	$ 6	$ (47)	$ 20	$ 17
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	154	49	13	—	38	42
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	17	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income (c)	6	—	—	—	—	—
Settlements	(263)	(84)	(19)	4	(58)	(59)
Transfers into Level 3 (d) (e)	—	—	—	—	—	—
Transfers out of Level 3 (e)	—	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	303	108	12	(5)	97	69
Balance as of June 30, 2025	$ 383	$ 108	$ 12	$ (48)	$ 97	$ 69

(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, 2026

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	$ 215	$ 156	Discounted Cash Flow	Forward Market Price	$ 7.89	$ 875.00	$ 54.52
AEP	FTRs	340	19	Discounted Cash Flow	Forward Market Price	(76.06)	238.16	1.56
APCo	FTRs	173	2	Discounted Cash Flow	Forward Market Price	(2.61)	56.36	3.92
I&M	FTRs	26	4	Discounted Cash Flow	Forward Market Price	(3.47)	42.39	1.06
OPCo	Energy Contracts	—	28	Discounted Cash Flow	Forward Market Price	21.81	106.13	51.87
PSO	FTRs	43	—	Discounted Cash Flow	Forward Market Price	(20.83)	1.43	(7.09)
SWEPCo	FTRs	42	—	Discounted Cash Flow	Forward Market Price	(20.83)	1.43	(7.09)

December 31, 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	$ 224	$ 144	Discounted Cash Flow	Forward Market Price	$ 5.65	$ 141.75	$ 50.61
AEP	FTRs	187	8	Discounted Cash Flow	Forward Market Price	(32.49)	21.68	0.49
APCo	FTRs	81	—	Discounted Cash Flow	Forward Market Price	(0.26)	17.55	3.47
I&M	FTRs	9	—	Discounted Cash Flow	Forward Market Price	(0.46)	21.68	1.60
OPCo	Energy Contracts	—	33	Discounted Cash Flow	Forward Market Price	21.44	85.92	50.10
PSO	FTRs	43	2	Discounted Cash Flow	Forward Market Price	(32.49)	8.54	(5.49)
SWEPCo	FTRs	37	2	Discounted Cash Flow	Forward Market Price	(32.49)	8.54	(5.49)

(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, 2026 and December 31, 2025:

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 2026 and 2025, adjusted for tax expense associated with certain discrete items.

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

	Three Months Ended June 30, 2026							
	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	3.5 %	0.6 %	2.4 %	(0.5)%	3.8 %	1.0 %	3.0 %	(7.7)%
Tax Reform Excess ADIT Reversal	(3.2)%	(1.5)%	0.2 %	(5.4)%	(2.6)%	(11.3)%	(6.7)%	(4.1)%
Production and Investment Tax Credits	(13.0)%	(0.1)%	— %	(13.8)%	(13.7)%	— %	(156.3)%	(110.8)%
Reversal of Origination Flow-Through	0.8 %	0.1 %	0.2 %	2.3 %	1.5 %	0.6 %	0.3 %	1.1 %
AFUDC Equity	(1.6)%	(1.6)%	(1.9)%	(1.0)%	(0.8)%	(1.8)%	(1.4)%	(2.7)%
Other	(1.0)%	0.2 %	(0.1)%	(0.6)%	(0.7)%	0.4 %	(5.4)%	(1.6)%
Effective Income Tax Rate	6.5 %	18.7 %	21.8 %	2.0 %	8.5 %	9.9 %	(145.5)%	(104.8)%

	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)%

	Six Months Ended June 30, 2026							
	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	2.2 %	0.6 %	2.4 %	(0.2)%	3.8 %	1.0 %	4.6 %	(12.8)%
Tax Reform Excess ADIT Reversal	(3.2)%	(1.5)%	0.2 %	(4.9)%	(2.5)%	(11.3)%	68.6 %	(6.8)%
Production and Investment Tax Credits	(11.7)%	(0.1)%	— %	(5.6)%	(10.1)%	— %	2,286.2 % (a)	(186.0)%
Reversal of Origination Flow-Through	0.8 %	0.1 %	0.2 %	2.0 %	1.4 %	0.6 %	(2.9)%	1.8 %
AFUDC Equity	(1.6)%	(1.6)%	(1.9)%	(0.9)%	(0.7)%	(1.8)%	14.2 %	(4.4)%
Flow-Through of CAMT	(1.4)%	— %	— %	(6.8)%	— %	— %	— %	— %
Other	(0.6)%	— %	0.1 %	0.1 %	(0.4)%	0.1 %	8.3 %	1.2 %
Effective Income Tax Rate	5.5 %	18.5 %	22.0 %	4.7 %	12.5 %	9.6 %	2,400.0 % (a)	(186.0)%

(a) The effective tax rate of PSO reflects a tax benefit. The resulting positive rate is attributable to the recognition of tax benefits in a period of pretax book losses.

	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)%

Income Taxes Paid

The following tables show the amount of income taxes paid or (received) on an interim basis, for each Registrant:

Six Months Ended June 30, 2026	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Income Taxes Paid/(Received)	$ 18	$ (9)	$ 85	$ (46)	$ 106	$ (40)	$ (31)	$ (28)
Transfer Credits	(64)	—	—	(4)	(50)	—	(6)	(3)
Total Cash Paid/(Received)	$ (46)	$ (9)	$ 85	$ (50)	$ 56	$ (40)	$ (37)	$ (31)

Six Months Ended June 30, 2025	**AEP**	**AEP Texas**	**AEPTCo**	**APCo**	**I&M**	**OPCo**	**PSO**	**SWEPCo**
				(in millions)				
Income Taxes Paid/(Received)	$ 59	$ (8)	$ (21)	$ (19)	$ 3	$ 1	$ (4)	$ (28)
Transfer Credits	(17)	—	—	—	—	—	(9)	(9)
Total Cash Paid/(Received)	$ 42	$ (8)	$ (21)	$ (19)	$ 3	$ 1	$ (13)	$ (37)

Federal and State Income Tax Audit Status

The statute of limitations (SOL) for the IRS to examine AEP and subsidiaries' originally filed federal income tax returns has expired for tax years prior to 2022. In July 2026, AEP received notification that its 2023 federal income tax return would no longer be audited and only remains open for potential items identified in subsequent year exams. In the second quarter of 2026, AEP received notification that its 2024 federal income tax return was selected for IRS examination. That examination began in July 2026.

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 2022. 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). This budget reconciliation legislation modifies and accelerates the phase out of technology neutral PTCs and ITCs available for wind and solar projects, adds new restrictions to guard against certain foreign ownership, influence or assistance with respect to otherwise credit-eligible projects and makes 100% bonus depreciation permanent for certain non-regulated entities. With the exception of bonus depreciation, this legislation is not expected to have a material impact on the Registrants.

On August 15, 2025, the Department of Treasury and the IRS issued new and revised wind and solar tax credit guidance, Notice 2025-42, which modified the definition of "begin construction" for tax purposes by eliminating the previously available 5% cost safe harbor standard for projects that begin construction after September 1, 2025. Notice 2025-42 was vacated in Oregon Environmental Council v. IRS, No. CV-25-4400 (D.D.C. June 6, 2026), which restored the availability of the 5% safe harbor. There is, however, uncertainty as to whether a court would overturn the ruling on appeal. Neither the ruling nor any related subsequent decision is expected to have a material impact on the Registrants.

On February 18, 2026, the Department of Treasury and the IRS issued additional interim guidance on the application of CAMT, Notice 2026-7. This guidance allows taxpayers to deduct certain tax-deductible repairs when determining adjusted financial statement income for CAMT purposes. This guidance is expected to result in a reduction to applicable Registrants' prior and future CAMT liabilities.

Additional significant guidance from the Department of Treasury and the IRS is expected on the tax provisions in recently enacted legislation. AEP will continue to monitor any issued guidance and evaluate the impact on AEP's future net income, cash flows and financial condition.

12. FINANCING ACTIVITIES

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

Common Stock (Applies to AEP)

ATM Program

In November 2025, AEP filed a prospectus supplement under which it may sell up to $3.5 billion of its common stock through an ATM program. In first quarter 2026, 2 million shares of common stock were issued for $264 million in net proceeds. In addition to these issuances and sales of shares of common stock, AEP also may use the ATM program to enter into forward sale agreements. See below for information regarding shares issued or expected to be issued under forward sale agreements.

Forward Equity Agreements

AEP has entered into the following forward sales under its ATM program and its March 2025 and May 2026 forward sale of equity agreements as follows:

	Final Maturity	Common Shares into Forward (Number of Shares)	Settled (Number of Shares) (a)	Settled (a)	Common Shares Remaining in Forward (Number of Shares)	Expected Proceeds (b)
				(in millions)		
March 2025 Forward Sale	December 2026	23	5	$ 500	18	$ 1,728
ATM Forward	December 2026	3	—	—	3	374
May 2026 Forward Sale	May 2028	24	—	—	24	2,932

(a) The 5 million shares were settled in fiscal year end 2025.
(b) Actual cash proceeds will be impacted by the timing of settlement. Forward prices are based on the public offering price (net of underwriting fees), increased for the overnight bank funding rate, less a spread and less expected dividends on AEP's common stock during the period the agreements are outstanding.

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, 2026	December 31, 2025
	(in millions)	
Senior Unsecured Notes	$ 40,068	$ 37,190
Pollution Control Bonds	1,636	1,637
Notes Payable	605	683
Securitization Bonds	2,305	984
Spent Nuclear Fuel Obligation (a)	336	330
Junior Subordinated Notes	4,682	4,681
Other Long-term Debt	1,176	1,817
Total Long-term Debt Outstanding	50,808	47,322
Long-term Debt Due Within One Year	2,821	3,194
Long-term Debt	$ 47,987	$ 44,128

(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 $389 million and $381 million as of June 30, 2026 and December 31, 2025, 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 2026 are shown in the following tables:

Company	Type of Debt	Principal Amount (a)		Interest Rate	Due Date
Issuances:		**(in millions)**		**(%)**	
AEP	Pollution Control Bonds	$	50	3.50	2030
AEP Texas	Senior Unsecured Notes		750	5.20	2036
AEPTCo	Other Long-term Debt		124	Variable	2028
AEPTCo	Senior Unsecured Notes		650	5.25	2036
APCo	Securitization Bonds		450	4.96	2035
APCo	Securitization Bonds		326	5.37	2040
APCo	Securitization Bonds		600	5.84	2046
I&M	Senior Unsecured Notes		650	5.60	2056
SWEPCo	Senior Unsecured Notes		300	5.30	2033
SWEPCo	Senior Unsecured Notes		600	5.20	2036
SWEPCo	Senior Unsecured Notes		500	5.90	2056
Non-Registrant:					
KPCo	Pollution Control Bonds		65	3.75	2030
Transource Energy	Other Long-term Debt		23	Variable	2028
Total Issuances		$	5,088		

(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 (a)	Interest Rate	Due Date
Retirements and Principal Payments:		**(in millions)**	**(%)**	
AEP	Pollution Control Bonds	$ 50	3.20	2026
AEP Texas	Securitization Bonds	12	2.29	2029
AEP Texas	Senior Unsecured Notes	50	3.81	2026
AEPTCo	Other Long-term Debt	613	Variable	2028
APCo	Other Long-term Debt	175	Variable	2026
APCo	Other Long-term Debt	1	13.72	2026
APCo	Securitization Bonds	15	3.77	2028
I&M	Notes Payable	2	3.44	2026
I&M	Notes Payable	3	5.93	2027
I&M	Notes Payable	10	6.01	2028
I&M	Notes Payable	9	6.41	2028
I&M	Notes Payable	19	4.89	2029
I&M	Notes Payable	20	Variable	2030
SWEPCo	Securitization Bonds	8	4.88	2039
SWEPCo	Senior Unsecured Notes	500	1.65	2026
Non-Registrant:				
KPCo	Pollution Control Bonds	65	4.70	2026
KPCo	Securitization Bonds	9	5.30	2045
Transource Energy	Senior Unsecured Notes	2	2.75	2050
WPCo	Notes Payable	15	6.89	2034
Total Retirements and Principal Payments		$ 1,578		

(a) In March 2026, SWEPCo retired $1 billion of 4.24% Affiliated Notes Payable due in 2028.

Financing Activities Subsequent Events

In July 2026, AEP made a capital contribution of $37 million to SWEPCo.

In July 2026, AEPTCo issued $75 million of variable rate Other Long-term Debt due in 2028.

In July 2026, I&M retired $10 million of Notes Payable related to DCC Fuel.

In July 2026, Transource Energy issued $9 million of variable rate Other Long-term Debt due in 2028.

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, 2026. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreements.

Dividend Restrictions

Subsidiary Restrictions

Parent depends on its subsidiaries to pay dividends to shareholders. AEP subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings. The Federal Power Act also creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to APCo and I&M.

Certain AEP subsidiaries have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The Federal Power Act restriction does not limit the ability of the AEP subsidiaries to pay dividends out of retained earnings.

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

Corporate Borrowing Program (Applies to all Registrant Subsidiaries)

AEP subsidiaries use a corporate borrowing program to meet their short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of June 30, 2026 and December 31, 2025 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, 2026 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, 2026	Authorized Short-term Borrowing Limit	
				(in millions)			
AEP Texas	$ 624	$ 186	$ 308	$ 98	$ (354)	$ 750	
AEPTCo	205	342	46	72	10	820	(a)
APCo	594	648	199	24	(109)	950	
I&M	146	855	37	159	63	750	
OPCo	198	42	95	17	(64)	750	
PSO	505	—	348	—	(394)	950	
SWEPCo	375	1,308	257	85	(311)	950	

(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 participates in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of June 30, 2026 and December 31, 2025 are included in Advances to Affiliates on AEP Texas' balance sheets. The Nonutility Money Pool participants' activity for the six months ended June 30, 2026 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, 2026
		(in millions)	
AEP Texas	$ 7	$ 7	$ 7

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. The amounts of outstanding loans to (borrowings from) AEP as of June 30, 2026 and December 31, 2025 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo's balance sheets. AEPTCo's direct financing activities with AEP and corresponding authorized borrowing limit for the six months ended June 30, 2026 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,	Loans to AEP as of June 30,	Authorized Short-term Borrowing Limit (a)
				(in millions)			
AEPTCo Parent	$ —	$ 578	$ —	$ 144	$ —	$ 156	$ —
SWTCo	2	—	2	—	2	—	50

(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, 2026	2025
Maximum Interest Rate	4.13 %	4.83 %
Minimum Interest Rate	3.53 %	4.14 %

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, 2026	2025	Average Interest Rate for Funds Loaned to the Utility Money Pool for Six Months Ended June 30, 2026	2025
AEP Texas	3.93 %	4.69 %	4.06 %	4.72 %
AEPTCo	3.95 %	4.68 %	4.01 %	4.62 %
APCo	4.00 %	4.69 %	4.01 %	4.58 %
I&M	3.93 %	4.69 %	3.93 %	4.64 %
OPCo	4.03 %	4.65 %	3.80 %	4.70 %
PSO	4.01 %	4.67 %	— %	4.68 %
SWEPCo	4.06 %	4.69 %	3.76 %	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, 2026			Six Months Ended June 30, 2025		
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	4.13 %	3.83 %	3.99 %	4.76 %	4.64 %	4.70 %
SWEPCo	— %	— %	— %	4.76 %	4.64 %	4.70 %

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**
2026	4.13 %	3.83 %	4.13 %	3.83 %	3.99 %	3.99 %
2025	4.76 %	4.63 %	4.76 %	4.63 %	4.69 %	4.69 %

Short-term Debt (Applies to AEP and SWEPCo)

Outstanding short-term debt was as follows:

		June 30, 2026		December 31, 2025	
Company	**Type of Debt**	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
		(dollars in millions)			
AEP	Securitized Debt for Receivables (b)	$ 900	3.95 %	$ 900	4.00 %
AEP	Commercial Paper	1,125	4.07 %	605	3.92 %
SWEPCo	Notes Payable	3	6.00 %	3	6.30 %
	Total Short-term Debt	$ 2,028		$ 1,508	

(a) Weighted-average rate of all borrowings outstanding as of June 30, 2026 and December 31, 2025, 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 2027. As of June 30, 2026, 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,	
	2026	2025	2026	2025
	(dollars in millions)			
Effective Interest Rates on Securitization of Accounts Receivable	3.94 %	4.53 %	3.93 %	4.57 %
Net Uncollectible Accounts Receivable Written-Off	$ 8	$ 6	$ 16	$ 14

	June 30, 2026	December 31, 2025
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 1,352	$ 1,230
Short-term – Securitized Debt of Receivables	900	900
Delinquent Securitized Accounts Receivable	71	66
Bad Debt Reserves Related to Securitization	44	42
Unbilled Receivables Related to Securitization	405	368

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, 2026	December 31, 2025
	(in millions)	
APCo	$ 193	$ 203
I&M	179	175
OPCo	553	501
PSO	182	140
SWEPCo	197	169

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Company	2026	2025	2026	2025
	(in millions)			
APCo	$ 3	$ 3	$ 7	$ 7
I&M	4	3	8	7
OPCo	7	8	15	15
PSO	3	3	6	6
SWEPCo	3	4	7	8

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

Company	Three Months Ended June 30, 2026	Three Months Ended June 30, 2025	Six Months Ended June 30, 2026	Six Months Ended June 30, 2025
	(in millions)			
APCo	$ 416	$ 430	$ 959	$ 1,035
I&M	648	545	1,345	1,130
OPCo	817	736	1,729	1,596
PSO	501	432	913	807
SWEPCo	474	456	895	884

13. VARIABLE INTEREST ENTITIES AND EQUITY METHOD INVESTMENTS

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

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

AEP holds ownership interests in businesses with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE, and if so, whether or not the VIE should be consolidated into AEP's financial statements. AEP has not provided material financial or other support that was not previously contractually required to any of its consolidated VIEs. AEP's interests in non-consolidated VIEs are accounted for under the equity method of accounting.

Consolidated Variable Interest Entities

Appalachian Recovery Funding (Applies to AEP and APCo)

In May 2026, Appalachian Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds primarily related to certain Virginia jurisdictional Property, Plant and Equipment balances for the Amos and Mountaineer Plants and certain Virginia jurisdictional major storm costs deferred to Regulatory Assets. Management concluded that APCo holds a variable interest in Appalachian Recovery Funding and is the primary beneficiary of the VIE because APCo has the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and has the obligation to absorb losses of, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. Therefore, APCo is required to consolidate Appalachian Recovery Funding. As of June 30, 2026, $35 million of the securitized bonds was included in Long-term Debt Due Within One Year - Nonaffiliated and $1.3 billion was included in Long-term Debt - Nonaffiliated on the balance sheets. Appalachian Recovery Funding's securitized asset was $1.4 billion as of June 30, 2026 which is presented in Securitized Assets on the face of the balance sheets.

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

The 2025 Annual Report includes a detailed discussion of AEP's and Registrant Subsidiaries' other consolidated VIEs.

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

June 30, 2026

Consolidated VIEs

	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Restoration Funding	APCo Appalachian Consumer Rate Relief Funding	APCo Appalachian Recovery Funding	SWEPCo Storm Recovery Funding	KPCo Cost Recovery Funding	AEP Credit	Protected Cell of EIS	Transource Energy
	(in millions)									
ASSETS										
Current Assets	$ 1	$ 91	$ 19	$ 19	$ 21	$ 16	$ 20	$ 1,353	$ 240	$ 50
Net Property, Plant and Equipment	—	163	—	—	—	—	—	—	—	691
Other Noncurrent Assets	72	82	87 (a)	64 (b)	1,361	309	455 (c)	12	—	7
Total Assets	$ 73	$ 336	$ 106	$ 83	$ 1,382	$ 325	$ 475	$ 1,365	$ 240	$ 748
LIABILITIES AND EQUITY										
Current Liabilities	$ 14	$ 91	$ 32	$ 31	$ 42	$ 23	$ 23	$ 1,293	$ 53	$ 45
Noncurrent Liabilities	59	245	73	50	1,333	300	450	—	136	321
Equity	—	—	1	2	7	2	2	72	51	382
Total Liabilities and Equity	$ 73	$ 336	$ 106	$ 83	$ 1,382	$ 325	$ 475	$ 1,365	$ 240	$ 748

(a) Includes an intercompany item eliminated in consolidation of $4 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, 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	$ 1	$ 118	$ 18	$ 18	$ 17	$ 24	$ 1,232	$ 223	$ 45
Net Property, Plant and Equipment	—	227	—	—	—	—	—	—	658
Other Noncurrent Assets	80	118	98 (a)	79 (b)	312	462 (c)	10	—	4
Total Assets	$ 81	$ 463	$ 116	$ 97	$ 329	$ 486	$ 1,242	$ 223	$ 707
LIABILITIES AND EQUITY									
Current Liabilities	$ 15	$ 118	$ 31	$ 31	$ 23	$ 30	$ 1,176	$ 56	$ 50
Noncurrent Liabilities	66	345	84	64	304	454	1	102	298
Equity	—	—	1	2	2	2	65	65	359
Total Liabilities and Equity	$ 81	$ 463	$ 116	$ 97	$ 329	$ 486	$ 1,242	$ 223	$ 707

(a) Includes an intercompany item eliminated in consolidation of $4 million.
(b) Includes an intercompany item eliminated in consolidation of $1 million.
(c) Includes an intercompany item eliminated in consolidation of $16 million.

Non-Consolidated Significant Variable Interests

OVEC (Applies to AEP and OPCo)

In November 2025 and December 2025, OPCo filed applications with the PUCO and FERC, respectively, to transfer its 4.3% ownership in OVEC to Parent and its 19.93% OVEC power participation entitlement to AGR. In December 2025 and April 2026, the PUCO approved the application and the FERC authorized the transaction, respectively. The transaction was completed in June 2026. As a result of the transaction, Parent remains responsible for the financial and other obligations of AGR under the intercompany power agreement.

The 2025 Annual Report includes a detailed discussion of AEP's and Registrant Subsidiaries' other significant variable interests in non-consolidated VIEs.

Equity Method Investment in Unconsolidated Entities

Gigawatt AI (Applies to AEP)

In August 2025, AEP and Gigawatt AI, Inc. (GWAI), a privately held company, entered into a new commercial arrangement. GWAI is focused on developing AI-centric operating systems and applications that optimize utility operations and infrastructure. AEP initially invested $100 million for a 10% ownership interest in the common stock and received a warrant for the option to acquire an additional 5% of GWAI's common stock for $50 million. In January and April 2026, AEP made two additional $25 million investments, each for an incremental 2.5% interest in GWAI's common stock because of GWAI's achievement of performance-based milestones. As a result, as of June 30, 2026, AEP holds 15% of GWAI's common stock with a cumulative investment of $150 million. In July 2026, AEP confirmed GWAI's achievement of two additional performance-based milestones. Pursuant to the agreements, the parties are progressing with the established procedural requirements for closing the investment, which is expected in the third quarter of 2026.

In connection with AEP's equity interest, AEP was granted the right to designate one of the three members of GWAI's board of directors. The board position is currently held by an officer of AEP and, therefore, the investment is a related-party transaction. AEP's board participation provides AEP with direct influence over GWAI's governance and oversight, while GWAI's founders retain all other equity interests and board representation. AEP also acquired a perpetual software license for software developed by GWAI.

The equity interest is accounted for as an equity method investment due to AEP's ability to exercise significant influence over certain GWAI policies. As of June 30, 2026, AEP's carrying value of the investment in GWAI was $150 million, which is recognized in Deferred Charges and Other Noncurrent Assets on the balance sheet. AEP's proportionate share of GWAI's losses was immaterial for the three and six months ended June 30, 2026.

The common stock warrant meets the definition of a derivative instrument and is therefore required to be carried at fair value on a recurring basis. The fair value of the common stock warrant and AEP's acquired perpetual software license were immaterial as of June 30, 2026.

The 2025 Annual Report includes a detailed discussion of AEP's and Registrant Subsidiaries' other equity method investments.

14. PROPERTY, PLANT AND EQUIPMENT

The disclosures in this note apply to AEP and PSO.

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 2026 and should be read in conjunction with the Property, Plant and Equipment note within the 2025 Annual Report.

Company	ARO as of December 31, 2025	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of June 30, 2026
			(in millions)			
AEP (b)(c)(d)(e)(f)	$ 3,712	$ 87	$ 3	$ (43)	$ 42	$ 3,801
PSO (b)(e)(f)	143	4	—	(3)	19	163

(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.

15. 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, 2026						
	VIU (a)	T&D	AEPTHCo	G&M	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 1,072	$ 662	$ —	$ —	$ —	$ —	$ 1,734
Commercial Revenues	852	473	—	—	—	—	1,325
Industrial Revenues (b)	702	145	—	—	—	—	847
Other Retail Revenues	60	14	—	—	—	—	74
Total Retail Revenues	2,686	1,294	—	—	—	—	3,980
Wholesale and Competitive Retail Revenues:							
Generation Revenues	236	—	—	47	—	—	283
Transmission Revenues (c)	153	223	599	—	—	(538)	437
Retail, Trading and Marketing Revenues (d)	—	—	—	603	—	(16)	587
Total Wholesale and Competitive Retail Revenues	389	223	599	650	—	(554)	1,307
Other Revenues from Contracts with Customers (e)	77	53	18	48	28	(50)	174
Total Revenues from Contracts with Customers	3,152	1,570	617	698	28	(604)	5,461
Other Revenues:							
Alternative Revenue Programs (f)	(10)	9	(7)	—	—	—	(8)
Other Revenues (b) (g)	(22)	4	—	11	2	(3)	(8)
Total Other Revenues	(32)	13	(7)	11	2	(3)	(16)
Total Revenues	$ 3,120	$ 1,583	$ 610	$ 709	$ 30	$ (607)	$ 5,445

(a) Beginning in the first quarter of 2026, PSO and SWEPCo incorporated fuel-related amounts into unbilled revenues to reflect consideration earned but not yet invoiced as of the balance sheet date. The impact of this change did not have a material impact on the financial statements or related disclosures.
(b) Amounts include immaterial affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEP Transmission Holdco were $475 million. The affiliated revenues for Vertically Integrated Utilities were $63 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Generation & Marketing were $16 million. The remaining affiliated amounts were immaterial.
(e) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Corporate and Other were $27 million. The remaining affiliated amounts were immaterial.
(f) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues. Amounts include immaterial affiliated and nonaffiliated revenues.
(g) Generation & Marketing includes economic hedge activity.

	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	$ 1,030	$ 612	$ —	$ —	$ —	$ —	$ 1,642
Commercial Revenues	750	420	—	—	—	—	1,170
Industrial Revenues (a)	704	145	—	—	—	—	849
Other Retail Revenues	61	15	—	—	—	—	76
Total Retail Revenues	2,545	1,192	—	—	—	—	3,737
Wholesale and Competitive Retail Revenues:							
Generation Revenues	237	—	—	38	—	—	275
Transmission Revenues (b)	157	197	699	—	—	(622)	431
Retail, Trading and Marketing Revenues (c)	—	—	—	538	—	(16)	522
Total Wholesale and Competitive Retail Revenues	394	197	699	576	—	(638)	1,228
Other Revenues from Contracts with Customers (d)	49	46	9	3	27	(44)	90
Total Revenues from Contracts with Customers	2,988	1,435	708	579	27	(682)	5,055
Other Revenues:							
Alternative Revenue Programs (e)	15	12	49	—	—	(47)	29
Other Revenues (a) (f)	12	2	—	(13)	3	(1)	3
Total Other Revenues	27	14	49	(13)	3	(48)	32
Total Revenues	$ 3,015	$ 1,449	$ 757	$ 566	$ 30	$ (730)	$ 5,087

(a) Amounts include immaterial 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. Amounts include immaterial affiliated and nonaffiliated revenues.
(f) Generation & Marketing includes economic hedge activity.

	Three Months Ended June 30, 2026						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO (a)	SWEPCo (a)
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 190	$ —	$ 348	$ 191	$ 472	$ 224	$ 208
Commercial Revenues	119	—	183	275	354	148	166
Industrial Revenues (b)	42	—	197	159	103	97	105
Other Retail Revenues	10	—	27	2	4	30	1
Total Retail Revenues	361	—	755	627	933	499	480
Wholesale Revenues:							
Generation Revenues (c)	—	—	83	147	—	4	42
Transmission Revenues (d)	195	580	59	11	27	14	55
Total Wholesale Revenues	195	580	142	158	27	18	97
Other Revenues from Contracts with Customers (e)	17	17	16	46	35	6	16
Total Revenues from Contracts with Customers	573	597	913	831	995	523	593
Other Revenues:							
Alternative Revenue Programs (f)	(2)	(9)	2	(6)	11	(2)	(5)
Other Revenues (b)	—	—	1	(25)	6	—	—
Total Other Revenues	(2)	(9)	3	(31)	17	(2)	(5)
Total Revenues	$ 571	$ 588	$ 916	$ 800	$ 1,012	$ 521	$ 588

(a) Beginning in the first quarter of 2026, PSO and SWEPCo incorporated fuel-related amounts into unbilled revenues to reflect consideration earned but not yet invoiced as of the balance sheet date. The impact of this change did not have a material impact on the financial statements or related disclosures.

(b) Amounts include immaterial affiliated and nonaffiliated revenues.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for APCo were $42 million primarily related to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEPTCo, APCo and SWEPCo were $471 million, $32 million and $22 million, respectively. The remaining affiliated amounts were immaterial.

(e) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for I&M were $17 million primarily related to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.

(f) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues. Amounts include immaterial affiliated and nonaffiliated revenues.

	Three Months Ended June 30, 2025						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 180	$ —	$ 366	$ 190	$ 432	$ 191	$ 191
Commercial Revenues	115	—	193	192	307	135	155
Industrial Revenues (a)	41	—	211	156	103	92	103
Other Retail Revenues	10	—	28	2	3	26	2
Total Retail Revenues	346	—	798	540	845	444	451
Wholesale Revenues:							
Generation Revenues (b)	—	—	77	138	—	1	48
Transmission Revenues (c)	176	682	46	19	22	16	55
Total Wholesale Revenues	176	682	123	157	22	17	103
Other Revenues from Contracts with Customers (d)	8	9	19	27	38	6	7
Total Revenues from Contracts with Customers	530	691	940	724	905	467	561
Other Revenues:							
Alternative Revenue Programs (e)	1	51	7	1	12	2	9
Other Revenues (a)	—	—	—	12	2	—	—
Total Other Revenues	1	51	7	13	14	2	9
Total Revenues	$ 531	$ 742	$ 947	$ 737	$ 919	$ 469	$ 570

(a) Amounts include immaterial 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. The remaining affiliated amounts were immaterial.
(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. Amounts include immaterial affiliated and nonaffiliated revenues.

	Six Months Ended June 30, 2026						
	VIU (a)	T&D	AEPTHCo	G&M	Corporate and Other	Reconciling Adjustments	AEP Consolidated
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 2,436	$ 1,395	$ —	$ —	$ —	$ —	$ 3,831
Commercial Revenues	1,651	882	—	—	—	—	2,533
Industrial Revenues (b)	1,351	273	—	—	—	—	1,624
Other Retail Revenues	119	29	—	—	—	—	148
Total Retail Revenues	5,557	2,579	—	—	—	—	8,136
Wholesale and Competitive Retail Revenues:							
Generation Revenues	598	—	—	99	—	—	697
Transmission Revenues (c)	316	437	1,185	—	—	(1,057)	881
Retail, Trading and Marketing Revenues (d)	—	—	—	1,373	—	(37)	1,336
Total Wholesale and Competitive Retail Revenues	914	437	1,185	1,472	—	(1,094)	2,914
Other Revenues from Contracts with Customers (e)	125	155	23	79	57	(107)	332
Total Revenues from Contracts with Customers	6,596	3,171	1,208	1,551	57	(1,201)	11,382
Other Revenues:							
Alternative Revenue Programs (f)	(7)	7	—	—	—	(11)	(11)
Other Revenues (b) (g)	(29)	14	—	110	4	(5)	94
Total Other Revenues	(36)	21	—	110	4	(16)	83
Total Revenues	$ 6,560	$ 3,192	$ 1,208	$ 1,661	$ 61	$ (1,217)	$ 11,465

(a) Beginning in the first quarter of 2026, PSO and SWEPCo incorporated fuel-related amounts into unbilled revenues to reflect consideration earned but not yet invoiced as of the balance sheet date. The impact of this change did not have a material impact on the financial statements or related disclosures.
(b) Amounts include immaterial affiliated and nonaffiliated revenues.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEP Transmission Holdco were $933 million. The affiliated revenues for Vertically Integrated Utilities were $118 million. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Generation & Marketing were $37 million. The remaining affiliated amounts were immaterial.
(e) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for Corporate and Other were $56 million. The remaining affiliated amounts were immaterial.
(f) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues. Amounts include immaterial affiliated and nonaffiliated revenues.
(g) Generation & Marketing includes economic hedge activity.

	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	$ 1,351	$ —	$ —	$ —	$ —	$ 3,733
Commercial Revenues	1,415	802	—	—	—	—	2,217
Industrial Revenues (a)	1,322	268	—	—	—	—	1,590
Other Retail Revenues	115	30	—	—	—	—	145
Total Retail Revenues	5,234	2,451	—	—	—	—	7,685
Wholesale and Competitive Retail Revenues:							
Generation Revenues	542	—	—	89	—	—	631
Transmission Revenues (b)	278	394	1,220	—	—	(1,072)	820
Retail, Trading and Marketing Revenues (c)	—	—	—	1,160	—	(32)	1,128
Total Wholesale and Competitive Retail Revenues	820	394	1,220	1,249	—	(1,104)	2,579
Other Revenues from Contracts with Customers (d)	101	108	18	4	70	(95)	206
Total Revenues from Contracts with Customers	6,155	2,953	1,238	1,253	70	(1,199)	10,470
Other Revenues:							
Alternative Revenue Programs (e)	18	16	61	—	—	(62)	33
Other Revenues (a) (f)	(20)	7	—	60	4	(4)	47
Total Other Revenues	(2)	23	61	60	4	(66)	80
Total Revenues	$ 6,153	$ 2,976	$ 1,299	$ 1,313	$ 74	$ (1,265)	$ 10,550

(a) Amounts include immaterial 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. Amounts include immaterial affiliated and nonaffiliated revenues.
(f) Generation & Marketing includes economic hedge activity.

	Six Months Ended June 30, 2026						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO (a)	SWEPCo (a)
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 348	$ —	$ 937	$ 434	$ 1,047	$ 410	$ 406
Commercial Revenues	233	—	376	526	649	270	324
Industrial Revenues (b)	79	—	383	305	194	186	197
Other Retail Revenues	21	—	53	3	8	54	6
Total Retail Revenues	681	—	1,749	1,268	1,898	920	933
Wholesale Revenues:							
Generation Revenues (c)	—	—	177	404	—	5	94
Transmission Revenues (d)	381	1,144	120	22	55	28	113
Total Wholesale Revenues	381	1,144	297	426	55	33	207
Other Revenues from Contracts with Customers (e)	37	23	33	74	117	9	24
Total Revenues from Contracts with Customers	1,099	1,167	2,079	1,768	2,070	962	1,164
Other Revenues:							
Alternative Revenue Program (f)	(4)	(1)	3	(4)	11	(2)	(5)
Other Revenues (b)	—	—	1	(31)	16	—	—
Total Other Revenues	(4)	(1)	4	(35)	27	(2)	(5)
Total Revenues	$ 1,095	$ 1,166	$ 2,083	$ 1,733	$ 2,097	$ 960	$ 1,159

(a) Beginning in the first quarter of 2026, PSO and SWEPCo incorporated fuel-related amounts into unbilled revenues to reflect consideration earned but not yet invoiced as of the balance sheet date. The impact of this change did not have a material impact on the financial statements or related disclosures.

(b) Amounts include immaterial affiliated and nonaffiliated revenues.

(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for APCo were $97 million primarily related to the PPA with KGPCo. The remaining affiliated amounts were immaterial.

(d) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for AEPTCo, APCo and SWEPCo were $925 million, $65 million and $42 million, respectively. The remaining affiliated amounts were immaterial.

(e) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues for I&M were $34 million primarily related to barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.

(f) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues. Amounts include immaterial affiliated and nonaffiliated revenues.

	Six Months Ended June 30, 2025						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Retail Revenues:							
Residential Revenues	$ 352	$ —	$ 972	$ 422	$ 999	$ 366	$ 384
Commercial Revenues	234	—	388	345	569	237	296
Industrial Revenues (a)	81	—	402	290	187	162	193
Other Retail Revenues	21	—	56	3	8	46	5
Total Retail Revenues	688	—	1,818	1,060	1,763	811	878
Wholesale Revenues:							
Generation Revenues (b)	—	—	167	333	—	5	104
Transmission Revenues (c)	349	1,188	88	29	46	30	94
Total Wholesale Revenues	349	1,188	255	362	46	35	198
Other Revenues from Contracts with Customers (d)	18	18	33	57	90	15	16
Total Revenues from Contracts with Customers	1,055	1,206	2,106	1,479	1,899	861	1,092
Other Revenues:							
Alternative Revenue Programs (e)	(1)	63	14	1	17	2	9
Other Revenues (a)	—	—	—	(20)	7	—	—
Total Other Revenues	(1)	63	14	(19)	24	2	9
Total Revenues	$ 1,054	$ 1,269	$ 2,120	$ 1,460	$ 1,923	$ 863	$ 1,101

(a) Amounts include immaterial 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. Amounts include immaterial affiliated and nonaffiliated revenues.

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

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of June 30, 2026. 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	2026	2027-2028	2029-2030	After 2030	Total
			(in millions)		
AEP	$ 44	$ 87	$ 39	$ 16	$ 186
APCo	8	32	25	12	77
I&M	2	9	5	2	18

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, 2026 and December 31, 2025.

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, 2026 and December 31, 2025.

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, 2026 and December 31, 2025. See "Securitized Accounts Receivables - AEP Credit" section of Note 12 for additional information.

The following table represents the amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on the Registrant Subsidiaries' balance sheets:

	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
June 30, 2026	$ 173	$ 137	$ 64	$ 73	$ 128	$ 92
December 31, 2025	146	113	67	74	22	65

16. SUBSEQUENT EVENTS

In July 2026, AGR entered into a PSA to acquire a 710 MW coal-fired generation facility located in Monongalia County, West Virginia. The transaction is subject to customary closing conditions, including approval from the FERC and other required governmental approvals. The agreement was signed to support growing energy demand in the region and strengthen AEP's ability to provide reliable power at affordable prices. The Company currently expects the acquisition to close in the fourth quarter of 2026 or the first quarter of 2027, although the timing and ultimate completion of the transaction are subject to receiving the required regulatory approvals and other closing conditions.

CONTROLS AND PROCEDURES

During the second quarter of 2026, 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, 2026, 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 2026 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 Note 5 - Commitments, Guarantees and Contingencies for additional information.

Item 1A. Risk Factors

The Annual Report on Form 10-K for the year ended December 31, 2025 includes a detailed discussion of risk factors. As of June 30, 2026, there have been no material changes to the risk factors previously disclosed in AEP's 2025 Annual Report on Form 10-K.

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 June 4, 2026, William J. Fehrman, the Chief Executive Officer and President 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. Fehrman's Rule 10b5-1 Trading Plan provides for the sale of up to 3,337 shares of common stock through March 31, 2027.

On June 5, 2026, Kate Dixon, the Senior Vice President, Chief Accounting Officer and Controller 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. Dixon's Rule 10b5-1 Trading Plan provides for the sale of up to 3,974 shares of common stock through March 31, 2027.

Except as described above, during the three months ended June 30, 2026, 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:
AEP‡ File No. 1-3525		
*3(b)	Amended By-Laws of AEP, as amended April 28, 2026 and effective May 1, 2026.	Form 8-K dated April 29, 2026, Exhibit 3.2
*10.1	Confirmation of Forward Sale Transaction, dated May 12, 2026, between AEP and Bank of America, N.A., in capacity as a Forward Purchaser.	Form 8-K dated May 14, 2026, Exhibit 10.1
*10.2	Confirmation of Forward Sale Transaction, dated May 12, 2026, between AEP and Goldman Sachs & Co. LLC, in capacity as a Forward Purchaser.	Form 8-K dated May 14, 2026, Exhibit 10.2
*10.3	Confirmation of Forward Sale Transaction, dated May 12, 2026, between AEP and Morgan Stanley & Co. LLC, in capacity as a Forward Purchaser.	Form 8-K dated May 14, 2026, Exhibit 10.3
*10.4	Confirmation of Forward Sale Transaction, dated May 13, 2026, between AEP and Bank of America, N.A., in capacity as a Forward Purchaser.	Form 8-K dated May 14, 2026, Exhibit 10.4
*10.5	Confirmation of Forward Sale Transaction, dated May 13, 2026, between AEP and Goldman Sachs & Co. LLC, in capacity as a Forward Purchaser.	Form 8-K dated May 14, 2026, Exhibit 10.5
*10.6	Confirmation of Forward Sale Transaction, dated May 13, 2026, between AEP and Morgan Stanley & Co. LLC, in capacity as a Forward Purchaser.	Form 8-K dated May 14, 2026, Exhibit 10.6
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 28, 2026, establishing terms of the 5.25% Senior Note, Series S due 2036.	Form 8-K dated May 28, 2026, 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
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated as of May 6, 2026	X							
3(c)	By-Laws, as amended June 23, 2026		X						
3(d)	Code of Regulations, as amended June 24, 2026						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

Exhibit	Description	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
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 Dixon
Kate Dixon
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 Dixon
Kate Dixon
Chief Accounting Officer
(Principal Accounting Officer and Authorized Signatory)

Date: July 30, 2026